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FINAL REPORT ON THE FEASIBILITY OF ELECTRIC SYSTEM MUNICIPALIZATION IN SAN FRANCISCO – TRANSMITTED BY SF/PUC RESOLUTION NO. 97-0048

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EXECUTIVE SUMMARY

Introduction and Purpose

For 91 years, the Pacific Gas and Electric Company (PG&E) has provided electric utility service to customers in San Francisco (SF). In recent years, for various reasons, PG&E's electric rates have been among the highest in the United States. In over 2000 other communities, electric utility service is provided by a governmental agency, such as a city department or public power authority.[1] On average, as discussed in chapter 1 of this report, municipal (muni) electric rates are lower than those for investor-owned utilities (IOUs) such as PG&E.

On the other hand, despite wide knowledge of the munis' average cost advantage, there have not been any major muni or public-power-agency formations in recent decades. There were a number of them in the first half of the century. A number of large U.S. cities have studied electric-utility municipalization in recent years, especially in response to high rates such as those experienced in SF, but no major city is at present on the verge of municipalizing its electric service. A few smaller publicly-owned electric utilities have been formed in recent years, as discussed in chapter 1.

The City and County of San Francisco (CCSF or The City) has considered electric municipalization, reviewed studies of it, and held voter referenda on it at various times. With recent renewed interest in municipalization, The City's Public Utilities Commission hired the Economic & Technical Analysis Group (ETAG) to prepare this feasibility study of municipalizing the electric service in San Francisco. The project's purpose is mainly to determine the economics of a public-agency takeover of electric service in SF (the muni option here), versus continuing PG&E service (the "business as usual", or BAU, scenario). Also, this study identifies the processes and steps that will be involved if CCSF elects the muni option, and it assesses the risks, other possible costs and benefits

[1]Figure from various recent documents, American Public Power Association (APPA).

The dependence of rates comparisons upon the acquisition cost is also a consequence of the great uncertainty over what that acquisition cost will be. The reason for the uncertainty is that the acquisition cost is determined in a legal process, called "condemnation", in which CCSF would seek a court order allowing it to take over PG&E's electric-distribution facilities in SF and setting the compensation that it must pay to do so. The compensation would almost certainly be determined by a lay jury based on the testimony of expert witnesses, who would opine on the value to a utility such as PG&E of the property to be taken. Because there have been no comparable transactions (i.e., no takings of large local electric-utility systems) in several decades, there is no market in which to assess such a value, and it must be done by means other than market surveys (the law's preferred way).

Thus, the experts would present various theories and analyses (mainly "replacement costs" and "income valuations"), within certain limits as prescribed by the court, as to how the value should be determined and what it is. Reviewing these theories using the best available data in the analyses, and in view of the legal standards for such evidence, we conclude in chapter 2 that the jury would likely be confronted by a range of estimates from $500-million to at least $1-billion and quite possibly significantly higher. It is also possible, but quite unlikely, that a figure as low as $300-million could be put before the jury. In short, the jury valuation is uncertain because the range will be at least 100% above the lower value, and possibly well over 300% above it -- and this range of uncertainty will attend the kinds of numbers with which most jurors will almost certainly have no experience: hundreds of millions of dollars.

Complete Economic Analysis of the Muni and BAU Options

Table ES-1, on the next page, shows that, by shifting our focus from valuations and total rates comparisons to the components of the rates, we may see better the true economics of the choice between the muni and BAU options. Chapter 4's detailed examination of the components of the rates reveals that there are two components in the table on which the rate differences for the two scenarios are *apparent, but not real differences* (as also explained briefly below). One of these differences artificially favors municipalization and a larger one artificially opposes it. Thus, when the effects of these two components on the economic comparison are canceled by zeroing out these two rate-

component differentials, as is done in the table, the comparison is more favorable to municipalization than is suggested by the total-rates comparison. Section 4.A explains in detail these two items (reviewed briefly here below), plus two contingency items, and three related risk considerations.

One item which is illusory in the CCSF rates column of the table is the "SF Distribution System Acquisition Valuation Premium". This percentage increase is simply the higher muni electric

Table ES-1: Economic Analysis of San Francisco's Electric-System Choice: Muni versus IOU/BAU (Cost Factors, Incorporating Restructuring Effects)

Cost/Rates Element	*PG&E Total Rates Component*	*CCSF Rates Changes Base/Low/High Cases*	*CCSF Real-Effect Economic Change*
Energy Supply, Including CTC & Transmission	55.3%	0.0%	0.0%
Distribution Operations, Customer Costs & Overhead	18.7%	-0.8%	-0.8%
PG&E Distribution Ownership Costs //	20.4%		
CCSF Profit Elimination Savings		-2.6%	0.0%
SF Distribution System Acquisition Valuation Premium	0.0%	+5.9% / -0.4% / +10.3%	0.0%
Federal & State Income Taxes	5.6%	-5.6%	-5.6%
Total	***100.0%***	***-3.1% / -9.4% / +1.3%***	***-6.4%***
Contingency Cases (See Chapter 4):			
CCSF Reliability, etc. "De-averaging"	0.0%	+3.0%	+3.0%
CCSF Avoids CTC "Tail"	0.0%	-1.0%	-1.0%
Total with Both Contingencies	100.0%	-1.1% / -7.4% / +3.3%	-4.4%

rate due to the extra amount CCSF would have to pay for PG&E's facilities, as compared to the depreciated book value used in setting PG&E's SF rates. Because regulated and muni ratemaking are each done on a cost-of-service basis, a higher valuation for the facilities means higher rates. However, what the PG&E and muni ratepayers purchase via their bills is quite different. The PG&E ratepayer is analogous to a renter of, say, a flat in San Francisco's Marina District -- while becoming a muni ratepayer/owner is analogous to becoming the owner of the flat. If a person lives in the flat, as either renter or owner, s/he will get the same service from it each month as s/he would in the other role. However, the owner has title to the future value of the property and the renter does not. A similar difference applies to IOU ratepayers, as compared to muni ratepayer/owners.[2] Thus, muni electric ratepayer/owners, as a group, have a claim on the future value of their utility assets (and today industry restructuring may be increasing those assets' value) which IOU ratepayers do not have on their utility's assets. In the right-most column, reflecting the real economics of the muni/BAU choice, we have "zeroed-out" the rates differential, which previously opposed municipalization by adding 5.9% to its costs in the base case and other amounts in the low- and high-cost cases.

The second *apparent, but not real difference* in this column is the "CCSF Profit Elimination Savings", which reflects the difference between PG&E's profit margin and muni-financing interest rates. When muni managers make imprudent or unreasonable decisions (which happen at times in nearly all enterprises), or when munis experience unfortunate contingencies, muni ratepayers must pay the costs of those events, either through increased utility rates or taxes. On the other hand, when these things happen with regulated IOUs, regulatory principles require ratemaking cost-disallowances to insulate ratepayers from them, because they have been paying through their rates a profit to the IOU all along that compensates its stockholders for carrying the risks of such events.[3] To continue

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[2] After we developed this analysis, we learned that APPA also makes a similar but more limited point in its September 1996 publication, "The Value of a Public Power Distribution System: Increasing, *Not* Decreasing". Our perspective is that of economists: the point, in economic terms, is that the renter and owner are operating at different points on the same "indifference curve", not on different curves; hence, there is no net economic difference between their situations, contrary to what their rate differentials at first suggest. That is, each gets what s/he pays for, but one pays more and gets compensatively more in return (the claim on future value, in addition to present service).

[3] For example, the CPUC has disallowed recovery through rates of hundreds of millions of dollars of costs for nuclear plants owned by California electric utilities. Public-power ratepayers would have to pay such costs either in electric rates, in taxes, or in reduced public services; there would be no equity cushion to absorb such disallowances for them.

the residential analogy, this item is akin to carrying insurance on the contents of the flat in the Marina. IOU ratepayers pay a monthly insurance premium in paying a market rate of return on the IOU's investment, while muni ratepayer/owners self-insure and thus avoid the monthly bill by carrying the risk.[4] In this item, the IOU ratepayers have a claim on future value, which they realize when IOU regulators disallow imprudent utility costs, and which muni ratepayer/owners cannot reap due to their virtual owner roles. In the right-hand column, reflecting the real economics of the muni/BAU choice, we "zeroed-out" the rates differential, which favored the muni option by cutting its costs by 2.6%.

To better convey the effect of municipalization, we note that the 5.6% income-tax savings (with a present worth of $186-million = $3,315-million x 5.6%, and a first-year $19.9-million total) would reduce a typical $75 monthly residential bill by $4.20. The 2.6% profit-elimination savings would yield a reduction of $1.95, and the acquisition premium expected value of 5.9% would increase the bill by $4.43. By comparison, other items about which concern has been expressed are very small. As one example, senior-executive and other high-level salaries for PG&E electric service comprise about 0.1% of the total cost of service; thus, even if they could be wiped out with no off-setting costs for CCSF (which is not the case), the effect would be about six cents ($0.06) on that typical bill. On the other hand, lowering CCSF's interest rate for the take-over with tax-exempt bonds (which we do not believe is possible) would save 2.8% in a representative year (2007), or $2.11 on the typical bill.

In sum as a result of these two adjustments and related considerations in chapter 4, the true economic comparison between the two options should be restated as follows. Savings to San Franciscans are more likely than not, and we find that they would be between 5% and 10%, as compared to PG&E service. A close second most likely is that savings would lie in the 0% to 5% range. Third and fourth most likely -- both highly unlikely -- are that, respectively, municipalization would yield savings above 10% of the BAU costs to San Franciscans and that higher costs would result for San Franciscans from municipalization. Thus, on an economic basis, the expected present-value of 30-year cost savings exceeds $200-million, as compared to a total of $3,315-million -- again, after purchasing the system and paying all the normal upkeep, expansion and operating costs.

[4]Again, from the economic viewpoint, the choice between these two positions is one of picking different locations on a given indifference curve -- i.e., they are equally "good" positions, even though the apparent price difference makes one look superficially more attractive than the other. Again, each ratepayer gets what s/he pays for, but one pays and gets more -- or, put another way, the two options have equal expected values to ratepayers, despite their price differences.

Thus, the real economic savings -- shown in the right-most column -- are almost completely due to a single factor: the avoidance of state and federal income taxes by munis, while IOUs must pay them and thus must be compensated for them in their regulated rates. This item favors the muni option by 5.6%. Another factor that adds a very small benefit, 0.8%, to municipalization for SF is that operating and maintenance costs for the SF electric distribution system are lower than the averages on PG&E's overall system, and San Franciscans would escape paying the differential (for IOU rates are based on system-average costs) by electing the muni option.[5] To decide whether municipalization is preferable to IOU ownership (BAU), these expected-value economic results -- i.e., expected net real economic savings of 6.4% -- must be weighed against the two electric-industry restructuring contingencies (shown at bottom of the table), and three other risk factors that attend the transition from IOU ownership to muni ownership. Those risk factors include acquisition-cost uncertainty (mis-valuation at trial), systematic efficiency differences (if any) between munis and monopoly-franchised/state-regulated IOUs, and net SF job losses due to PG&E possibly moving its corporate offices from SF in response to municipalization. Chapters 3 and 4 discuss all these items.

To sum up the salient facts: The initial cost is highly uncertain, probably (not certainly) lying between \$500-million and \$1-billion. Expected electric rates would be lower by 3%, although they would be higher in the early years and lower in later years. The expected net economic value, though, is a benefit equivalent to electric-bill reductions of 6%. However, both the rates and true economic effects are subject to uncertainties that could favor or oppose municipalization as they are realized.

Recommendation: If Proceeding, More Extensive Valuation Study Is Next

As a result of our analyses, we recommend that, if -- and only if -- CCSF is inclined as a policy decision to pursue municipalization on the basis of these prospective costs, risks and benefits, and if it can spare the dollars from other pressing needs, then it should next proceed to a more extensive

[5] Arguments can reasonably be made, as discussed in chapter 4, that this and other contingency factors shown in the table do not reflect the muni/IOU choice, but instead reflect state electric-industry pricing policies. The income-tax-based differences are systematic and inherent only to the muni/IOU choice. Economies of scope, scale and operating efficiency, as discussed in chapter 3, are also inherent to the muni/IOU choice, but due to SF's size and other operations, we have assumed that none of these factors will negatively affect the muni option, relative to the BAU scenario.

valuation study. If such a study is undertaken, it should focus on the condemnation valuation, especially on the "replacement-cost" methods discussed in chapter 2. The foregoing analysis has shown that the rates comparison is dominated by three factors, led by the acquisition-cost uncertainty, which is mainly due to replacement-cost uncertainty. The true economic assessment, however, is dominated by the fact that the muni option avoids state and federal income taxes which IOUs must pay and which they pass on to their ratepayers (a factor virtually certain for the foreseeable future). While clearing up uncertainty about condemnation valuation has a major effect on rates, it plays only a minor role in the true risk-adjusted economics. The present study is sufficient as a basis to understand the real economics of the choice between the two options, and to make a municipalization policy decision, and the more detailed valuation study is not, in our view, needed for that purpose.

One could argue that an extended valuation study is merited because the expected benefit from municipalization is high enough -- even at the modest levels, relative to PG&E's rates, that this study finds -- to justify the roughly $1-million cost of the extended valuation study. On the other hand, this expected benefit must be weighed against the likelihood that, mainly as a consequence of undertaking the study, municipalization will proceed. From this view, if the present study is sufficient, as we believe it is, to make the policy decision, then the extended study is needed only if the policy decision is to pursue municipalization. (Under the terms of the contract for this project, ETAG may not be a candidate to do this follow-on work.)

As discussed in section 5.A, our investigations have also turned up a potential legal trip-wire for municipalization that may be avoided by an abundance of caution in proceeding and a strong showing on the benefits, if net benefits they prove to be, for the muni option. An extended valuation study may help avoid that trip-wire, or it may be counter-productive, depending on its outcome. The legal problem is that a 1992 provision added to state law applying to municipalizations now makes the condemnation trial court (i.e., the trial judge) the authority who must ultimately rule on whether The City has made an adequate showing that municipalization is in the public interest, all factors considered. Before this provision was added, the determination of the CCSF's Board of Supervisors would have been final on this matter, as long as the Board had some reasonable basis for a finding of what is called, in the law, "public necessity". As a result of this provision, before the condemnation

case can proceed to jury selection and trial on the valuation, PG&E will have a full opportunity to persuade the court, via a most-likely extensive factual showing (essentially, a bench trial before the jury trial) that municipalization is not in the public interest or "necessity" -- i.e., that it is an inferior option, considering the full range of public policy concerns and private losses and risks at stake. While an extended valuation study will not be fully dispositive on this issue in any event, it may help resolve the uncertainty, and it will very likely be required if The City proceeds with municipalization.

Overview and Roadmap for the Report

Our study incorporates the effects of recent changes at the state and federal levels in electric regulation and industry organization, assuring that it is current and useful for policy and planning. It thoroughly reviews municipalization success factors, obstacles and recurring problems. While it cannot provide the ultimately precise original- and replacement-cost estimates, it is definitive on the other valuation issues, including the role of valuation for the municipalization policy decision for SF. It is also definitive on the rates and economic comparisons for the muni/IOU choice, as well as for assessment of the other (non-valuation) factors in those comparisons and the specification and role of non-quantifiable factors in the decision. This study also compares our results with previous studies and extensively reviews comparative muni/IOU experience nationally and in California. It presents a process map, time table and rough budget for the road to municipalization, if it is chosen, and it reviews its legal and financial issues, other risks, and alternatives and environmental impacts.

The road-map for this study is as follows. Chapter 1 presents a survey of the experience of other electric munis and municipalization efforts to provide insight and guidance for the study. Chapter 2 addresses acquisition valuation issues, and chapter 3 handles all other cost factors. Chapter 4 pulls together all factors to produce a comprehensive economic analysis. These three chapters constitute the core of this feasibility and cost/benefit study. Finally, chapter 5 addresses procedure, time table and other matters, while chapter 6 shows how we have fully incorporated into our analyses the effects of electric-industry restructuring. Each chapter begins with a 3-11 page introduction and summary, followed by the substantive analysis in the body of the chapter. A separate volume includes workpapers and responses to formal comments on the report drafts and to SFPUC questions.

CHAPTER 1: Survey of Other Munis and Municipalizations

Overview and Summary of Chapter 1

This chapter reviews experience of existing municipal (muni) electric utilities and attempted municipalizations for guidance on the prospects and problems for municipalization of electric utility service in San Francisco (SF). Our review involved four subtasks, reported in the four sections of this chapter and related workpapers, and summarized below in this summary section:

- Comparing investor-owned utilities (IOUs) and munis' electric rates in California and nationally (section 1.A);
- Comparing for six large cities, whose experience may be instructive for SF, the electric rates of their muni utilities and of neighboring IOUs (section 1.B);
- Reviewing municipalizations of electric service attempted in the electric service area of Pacific Gas and Electric Company (PG&E) since 1975 (section 1.C); and
- Identifying: principal factors contributing to success of efficient, low-rate munis; obstacles to successful operation of munis; and significant recurring problems in the industry (section 1.D).

Comparison of Muni and IOU Electric Rates in California and Nationally: Section 1.A and its appendices compare muni and IOU electric rates, both in California and nationally. Our analyses show that such comparisons provide only very limited guidance on whether retail electric rates would be higher, lower or about the same for service by the City and County of San Francisco (CCSF or The City), as compared to continuing service by PG&E (the "business as usual" or BAU scenario).[1] Overall, the comparisons show that electric rates for munis are significantly lower (about 14%) than those for IOUs. However, rates for munis and IOUs show much variation: sometimes

[1] The BAU scenario involves PG&E providing electric-utility distribution service and customers buying their electric energy either from PG&E or from another supplier, with delivery by PG&E, as provided by recent decisions of the California Public Utilities Commission (CPUC) and the recently enacted Assembly Bill 1890 (Brulte, 1996).

muni costs exceed those for IOUs and sometimes they are much lower, too. (Data and sources on which we rely in these comparisons, as footnoted below, are the same used by the American Public Power Association (APPA) in its annual survey of muni and IOU rates, as published most recently in *Public Power*, January-February 1996, pages 40-43 -- and thus its data thus show the same results.) In any event, the result in SF, as later chapters of this study show, depends on factors that these comparisons do not reflect. Instead, the variability in these national and California comparisons emphasizes the need for the direct analysis specific to SF provided in the rest of this report.

Analyses of Electric Cost Components for Six Cities Comparable to SF: Section 1.B delves into the reasons for the rate differentials between muni and IOU electric service shown in section 1.A. It examines cost components for six muni electric service areas comparable to SF and for the six major IOUs which are those munis' nearest neighbors. By comparing cost components for somewhat comparably situated munis and IOUs, we seek to determine which factors lead to the muni cost advantages shown in section 1.A -- and we develop further guidance for analyzing municipalization in SF in later chapters. Our muni/IOU-pair comparisons in section 1.B and its workpapers show that average cost differentials between existing muni and IOU electric-utility systems are dominated by the munis' lower gross costs of capital. In "gross costs of capital" we include two major factors:

- First, munis are fully leveraged with 100% debt (or debt and ratepayer) financing, currently at rates (per section 2.F) of about 7.5% per annum (and 6% for tax-exempt bonds that may be used for system refunding and normal growth), while IOUs are usually financed about 50% with debt (at similar interest rates) and 50% with equity (mainly common stock) on which they must generate higher earnings (or profits), typically at rates of 11.6% presently (to pay stock dividends and maintain the retained earnings capital markets require); and
- Second, munis are exempt from state and federal income taxes on their operation, while IOUs must pay such income taxes on their equity earnings (profits).[2]

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[2] APPA, in its publication"Straight Answers to False Charges Against Public Power" at pages 6-7, argues that assessment of the rate differences between munis and IOUs should adjust for reductions in IOU rates due to deferred income taxes. Since PG&E's 1995 Annual Report to stockholders (at page 25) shows that PG&E's average tax rate on income exceeds its marginal rate in most recent years, these effects now actually raise PG&E's rates slightly, instead of lowering them; hence, there is no net income-tax break for PG&E. In any event, a truly level playing field for munis and IOUs would

Both of these two costs get passed along to electric ratepayers of IOUs, and they increase their electric bills substantially, as compared to muni electric bills. From the current costs of capital, we computed that the combination of these two factors -- that is, the effect of the difference in gross costs of capital -- can raise by about 82% the financing costs of utility operations (or as much as 126% with full tax-exempt financing) -- and financing costs are usually either the largest or second largest cost component for electric utilities. Of this 82% increase for this factor, the equity return (profits) accounts for less than one-third, while the income-tax costs account for more than two-thirds. Our analyses for the six pairs show that, absent these two cost advantages, munis are not significantly more or less efficient in delivering electric energy to ratepayers. These cost-component comparisons for the six pairs reflect the situation between long-extant munis and IOUs. For new municipalization efforts such as CCSF would undertake to provide retail electric service to SF, the gross-cost-of-capital advantage will still be present. However, it may be offset by other factors, discussed in sections 1.C and 1.D, resulting from the muni-formation process, instead of continued muni versus IOU operation and financing.

Recent Municipalizations in the PG&E Service Area: Section 1.C shows that, since 1975, only one actual electric municipalization attempt (by Hayfork Valley and the Trinity County Public Utility District) has been made in the PG&E service area. Also, one specialized public power agency was formed (i.e., an entity with limited functions that is not a full-service electric muni, as SF is contemplating). While successful, the two situations differed from SF's in important ways; for example, they involved from 0.07% to less than 2% of the number of customers that would be involved in SF. Nonetheless, lessons can be learned from them, as well as from a recent voter initiative in Calaveras County that lost at the polls. As discussed in section 1.C, although it appears that rates are lower following the Trinity County municipalization than they were for PG&E service, this was partly because PG&E was willing to sell off this service area on terms mildly favorable to the buyers since it was not a very profitable part of its system. On the other hand, PG&E has stated

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be one in which both were taxed at the same level in a given location for a given service delivered. A complaint that IOUs get a non-level-playing-field benefit from deferred taxes is backwards, because the fact that they are taxed, where munis are not, is a tilting of the playing field against them. Such a complaint thus would mean the field should be tilted even further.

in answering our data requests that it will oppose any municipalization attempts in SF.[3] Due to such opposition in a contested condemnation case, chapter 2 shows that CCSF is not likely to be able to acquire the SF facilities on terms comparably attractive to those for Trinity County, where PG&E wanted to sell the facilities. Hence, while the review in section 1.C provides some insight into the economics of municipalization, it mainly highlights the need for a detailed analysis based on the particulars of the SF situation.

Success Factors, Obstacles and Recurring Problems for Munis and Municipalization: Based on the analyses in sections 1.A-C, section 1.D distills and summarizes the success factors, obstacles and recurring problems for electric munis and municipalization, by aggregating them in two classes. First, section 1.D discusses those items that arise in establishing a muni electric utility and which affect the economics of the municipalization decision and help guide our work on subsequent tasks:

- Strong voter support and public-agency staying power are essential; PG&E will resist vigorously and litigate aggressively, and the long process wears down many efforts.
- Physical severance damage to PG&E's system and needs to reconfigure the separated electric distribution systems will not be serious problems for SF, as they were for a small muni effort; however, a related specific physical issue -- the role of local power plants -- does arise for SF, but our investigations showed it not to be a serious problem for SF.
- Valuation in condemnation of the SF electric distribution system, rights and ancillary facilities taken -- or the price CCSF will have to pay to acquire the system -- is the largest rates-factor difference between the muni and BAU options, and the exact amount of difference is highly uncertain.
- "Stranded costs" of PG&E generation resources (i.e., the uneconomically high costs IOUs may claim they would have been able to recover from ratepayers without municipalization or "bypass" by ratepayers buying electric power from sources other than their present IOUs) have in recent years emerged in municipalization discussions and in IOU ratemaking as a

[3] Letter of 13 August 1996 from Thomas P. Evans, Manager of PG&E's San Francisco Division, to ETAG.

major issue. This issue has recently been resolved in California and for SF by the passage and signing of Assembly Bill (AB) 1890 (Brulte, 1996), which assures that those costs will be collected by the IOUs, even if some areas elect the public-power route or if customers are able to effect competitive bypass. However, consideration of this issue here does highlight the need to reflect the "competition transition charges" (CTCs, or payment for stranded costs) in our analyses, and we do so in subsequent chapters.

Second, we discuss factors involving operations of the muni electric utility, once it is established, that affect the economics of municipalization versus the business-as-usual scenario:

- Having a gross cost of capital well below PG&E's is essential to municipalization success, especially because part of this advantage will almost certainly be offset in setting rates by the condemnation value CCSF will have to pay to acquire PG&E's SF facilities, as compared to the book value of PG&E's SF electric distribution system. (See section 2.F for computation of the PG&E and CCSF gross costs of capital).
- Energy-supply costs are traditionally an issue. Chapter 3 shows that these costs are equal for the muni and BAU options, due to restructuring of the electric-utility system in California under AB 1890 and to the unavailability of new "muni preference" or other bulk power and energy sources with lower costs than are available in the BAU scenario.
- Size and scope economies and relative muni/IOU operating efficiencies are always issues. Size economies (or economies of scale) refer to the fact that, for many business and public-service operations, per-unit (or per-person, etc.) costs decrease as the number of units (persons) served increases; these factors, where they exist and are substantial, tend to favor the larger service area, which is usually the IOU and is certainly PG&E in this study. Scope economies refer to the fact that producing two or more services or goods together can be less costly than doing so separately; these economies do not necessarily favor IOUs or munis, because each of them can offer such benefits (with PG&E offering gas and electric service, while CCSF may reap scope economies from running both electric and water distribution and sewer services). The question of whether publicly owned utilities are inherently more or less efficient in their operation, as compared to regulated private monopolies, is usually discussed in connection with these two factors, as we do in section 1.D.

A. *Survey of National and California Muni and IOU Electric Rates*

1. *Introduction*

In this section we compare electric rates of municipal and IOU systems in California and nationwide, and in the next section we examine the cost basis for the differences in the rates by looking closely at six muni/IOU neighboring utility pairs. The primary purpose of this part of the report is to identify specific cost factors that cause the differences in the average electric rates between munis and IOUs, and, if applicable, to include those factors in our analysis of the benefits and costs of creating a municipal electric utility in SF.

The rate comparisons presented in this chapter demonstrate that munis generally have been able to provide service at lower rates to consumers than IOUs both in California and nationwide. This muni/IOU rate variance can theoretically be explained by three factors: 1) business conditions faced by IOUs and munis (mainly loads and resources differences, and resulting economies of scope and scale); 2) financing cost differences between IOUs and munis (including IOUs' equity profits and income-tax payments); and 3) management efficiency differences between IOUs and munis. By comparing muni and IOU pairs, and through separating cost of service into component parts in the next section, we identify causes of rate differences and use relevant comparative cost data in developing assumptions for municipalization in SF.

Revenue-per-kWhr comparisons show whether customers of munis are receiving electricity for a lower or higher cost than customers of IOUs. If munis consistently deliver electric service for a lower cost than IOUs, all else being equal, investigation of municipalization as a means to lower costs for San Franciscans is warranted. The rate analyses below demonstrate that municipal utility systems have in fact generally been able to provide electric service at a lower cost to their consumers than IOUs. Furthermore, the rate differential is not a recent phenomenon: over the last ten years, California munis have consistently provided electricity at lower rates than IOUs, and currently muni

rates for electric service are about 18% lower than PG&E's average rate. Nationwide, muni rates are about 14% lower than rates incurred by customers of IOUs.

2. *Background Data on IOUs and Munis*

Before presenting details of the rate comparison, we show background data on the size and characteristics of munis and IOUs in California in Table 1-1. Additional comparative statistics are shown in Workpapers 1-A. Table 1-1 and information in Workpapers 1-A show data for each California muni and for PG&E and the state's other two large IOU electric utilities, the Southern California Edison Company (SCE) and the San Diego Gas and Electric Company (SDG&E). The source of data in Table 1-1 is The Electric World Directory , 1997 105th Edition, published annually by McGraw Hill.

Table 1-1 also demonstrates that, in California, the Sacramento Municipal Utility District (SMUD), is probably most comparable in size and complexity to what CCSF's system would be if it provided full retail service. SMUD's 473,000 customers are comparable to SF's 331,000 (in 1994 -- more than 334,000 now) retail customers. Anaheim, like Los Angeles, is somewhat less comparable to SF for purposes of this study due to a size-differential factor in the 3-4 range (albeit on the low side, while Los Angeles lies on the high side). However, we believe there is sufficient comparability to San Francisco electric service to merit including data for at least these three municipal electric utilities (LADWP, SMUD and Anaheim) and perhaps those of Riverside, Glendale, Pasadena and Burbank. These munis are included in our cost structure analysis below. The other munis in California are small, not very comparable, and lacking reported data -- and so the value of their data is limited for this report.

Table 1-1

California Municipal and Investor Owned Electric Utility Systems

Investor-Owned Utility Companies	Number of Customers	Retail Sales (MWHr)	Owned Capacity (MW)	Peak Load (MW)	Number of Electric Employees
PACIFIC GAS AND ELECTRIC CO.	4,387,054	72,321,927	14,970	15,988	15,072
SOUTHERN CALIFORNIA EDISON CO.	4,165,541	71,481,575	15,855	17,548	18,351
SAN DIEGO GAS & ELECTRIC CO.	1,144,387	15,522,920	2,416	3,260	2,895
TOTAL IOU's	9,696,982	159,326,422	33,241	36,796	36,318
Municipal Utility Systems & HHW&P					
LOS ANGELES DEPT OF WATER & POWER	1,343,480	20,513,243	7,394	4,863	8,730
SACRAMENTO MUNICIPAL UTILITY DIST	479,820	8,458,888	903	2,240	2,340
ANAHEIM PUBLIC UTILITIES DEPT.	103,937	2,685,931	158	514	304
SANTA CLARA ELECTRIC DEPT.	45,973	2,178,546	86	397	109
RIVERSIDE UTILITIES DEPT.	88,414	1,638,625	38	432	280
HETCH HETCHY WATER & POWER	19	1,476,554	389	391	33
PASADENA WATER AND POWER DEPT.	57,818	1,092,771	205	274	230
PALO ALTO ELECTRIC UTILITY	27,441	1,046,831		193	275
VERNON MUNICIPAL LIGHT DEPT.	1,977	1,032,420		174	40
GLENDALE PUBLIC SERVICE DEPT.	82,496	1,031,034	279	275	272
BURBANK PUBLIC SERVICE DEPT.	50,972	950,544	349	245	282
REDDING ELECTRIC DEPT.	34,431	765,548	4	182	112
ROSEVILLE ELECTRIC DEPT.	28,066	625,517		162	68
ALAMEDA BUREAU OF ELECTRICITY	31,445	461,698		72	102
LODI MUNICIPAL ELECTRIC SYSTEM	21,998	356,766		101	40
COLTON ELECTRIC UTILITY DEPT.	16,480	208,197		57	39
AZUSA LIGHT & WATER DEPT.	14,350	352,622		49	62
LOMPOC UTILITY SERVICES/ELECTRICA	14,447	118,828		19	23
BANNING ELECTRIC DEPT.	9,633	106,457		28	
UKIAH MUNIC ELECTRIC SYSTEM	7,054	101,000	3	26	
HEALDSBURG MUNIC ELECTRIC DEPT.	4,693	62,347		15	
CITY OF SHASTA LAKE	3,854	59,604		14	
CITY OF NEEDLES	3,029	49,589		16	41
GRIDLEY MUNICIPAL UTILITIES	2,214	33,945		9	4
BIGGS ELECTRIC DEPT.	621	7,350		1	
TOTAL MUNI	2,474,662	45,414,855	9,808	10,749	13,386
MUNI AS PERCENT OF IOU	25.52%	28.50%	29.51%	29.21%	36.86%

3. Rate Comparisons of IOUs and Munis

Figures 1-1 through 1-4, using the most recent data available, present comparisons of rates for the California and U.S. muni and IOU electric utilities. Figure 1-1, below, ranks IOUs and munis in California according to the 1995 total retail rate level. The bottom two bars on the graph show the weighted average rate for the three IOUs and all of the munis. Figure 1-1 demonstrates that the PG&E rate, 10.5 cents/kWh, exceeds the rate of all utilities except four small munis and SCE. Overall average rates for all major munis are significantly below those of PG&E and SCE, with SDG&E's average rates lying in the top cluster of muni average rates

Figure 1-1

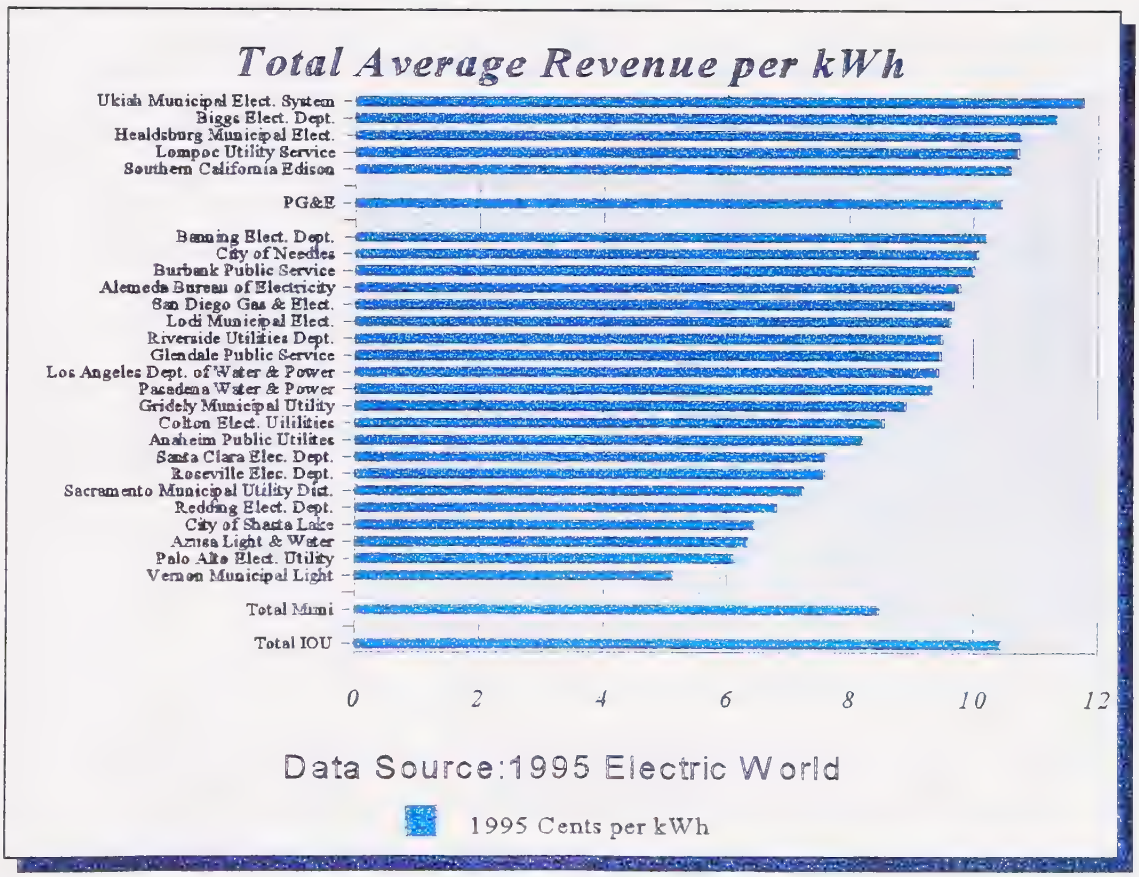
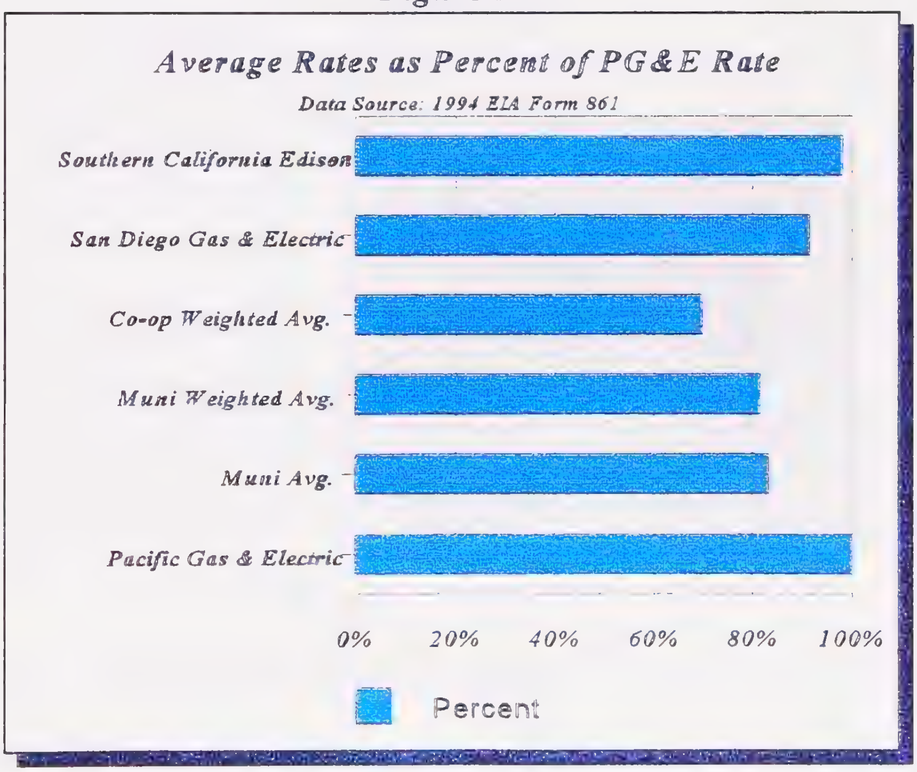


Figure 1-2, below, shows average rates as a percentage of the average rates for PG&E, which currently provides retail electric service in SF The data, computed from 1994 data reported in the U.S. Energy Information Agency (EIA) form 861, shows that PG&E has higher average rates than any of the other sources. As a result, the weighted overall average muni rate is 81.5% of that for PG&E, and 83% of the weighted-average overall IOU rate in the state. Note that PG&E's average rate was slightly lower than SCE's average rate in 1995 (see Figure 1-1).

Figure 1-3, on the next page, compares rates for munis and IOUs on a nationwide basis.[4] This analysis tests whether the muni/IOU rate differentials extant in California are also present elsewhere in the U.S. Figure 1-3 presents the ratio of muni to IOU rates on a state-by-state basis.

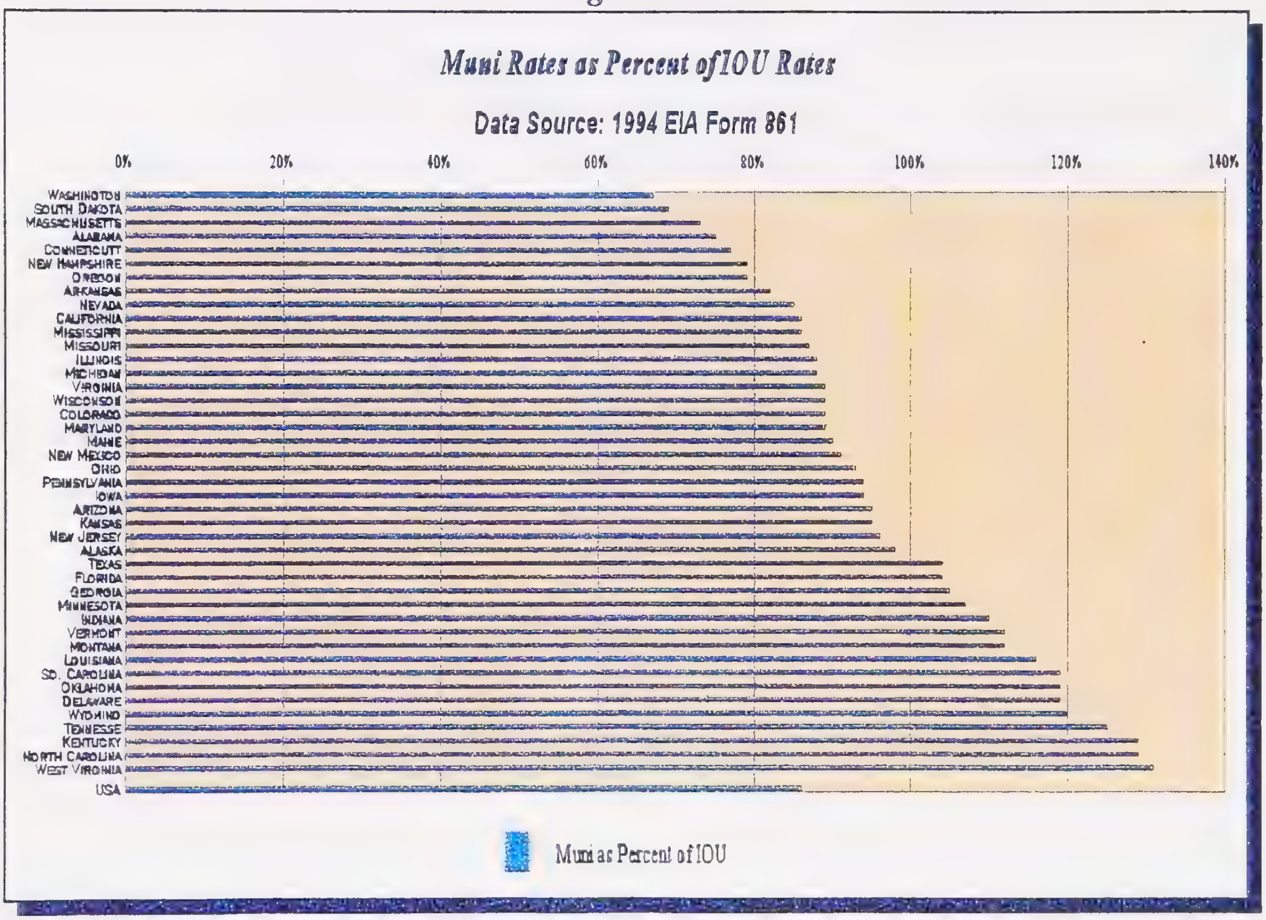
Figure 1-2



[4]APPA's "Straight Answers to False Charges Against Public Power", at page 5 and elsewhere, refers to the same data for other years, although it sometimes also uses comparisons by rate class, which we do not do here.

This chart provides comparisons for 1994 using data from the EIA Form 861, the latest year for which data are available. It shows that California's weighted-average muni electric overall rate is about 86% of that for the state's IOUs. Although this percentage is lower than that for about three-fourths of the states, it equals the national average of 86%, because muni electric sales are concentrated more heavily in California and other states with lower-than-average muni/IOU percentages. Figure 1-4, on the next page, shows that the statewide muni and IOU weighted electric-utility rates have been a steady more-or-less 10% to 20% lower than IOU rates over the last decade.

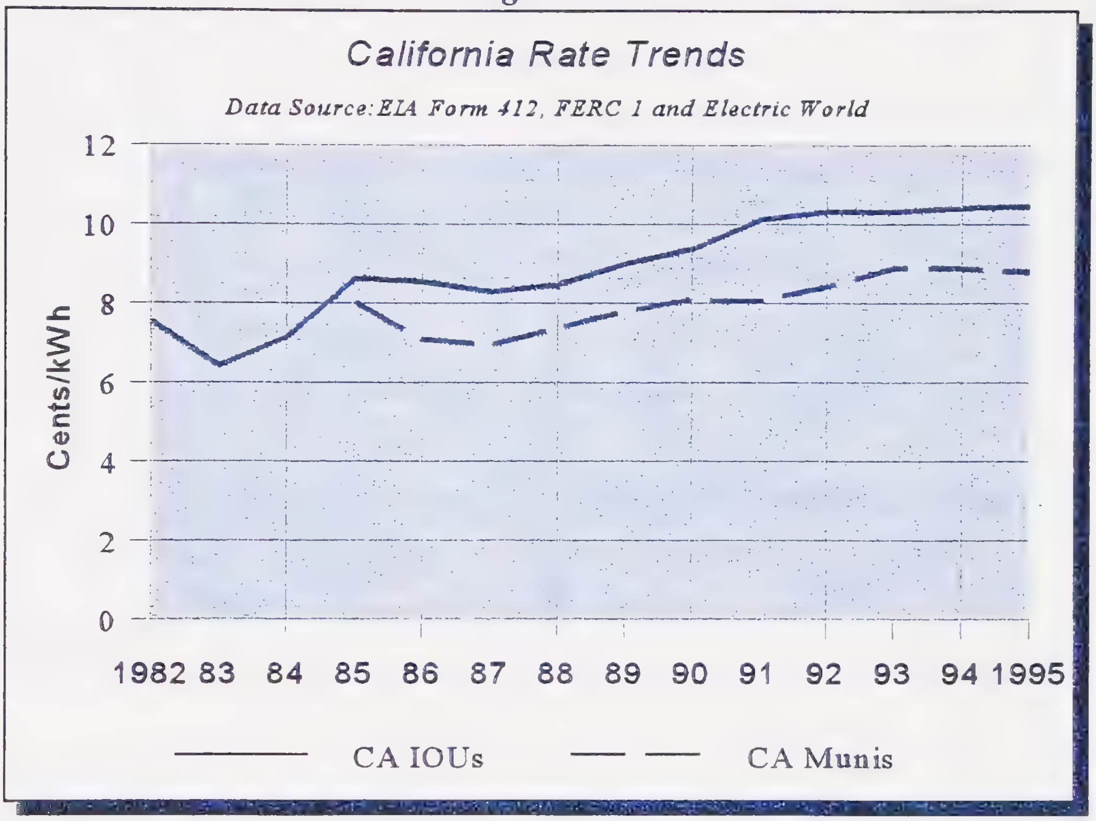
Figure 1-3



The rate comparisons discussed here offer at most only very limited guidance to the ultimate question of whether retail electric rates in San Francisco would be higher, lower or about the same

under a municipalization scenario, as compared to continuing PG&E's IOU franchise. For example, the rates for all the major munis reflect the fact that they have been in operation for a long time, and thus their plant is implicitly valued for rate purposes at book cost (original cost, less depreciation), which is often a low figure. Similarly, their bulk-power-supply contracts were mostly signed as long-

Figure 1-4



term purchases during the time the industry was highly regulated, and future costs are likely to differ from the patterns of those contracts whether retail ratepayers in SF are served by CCSF or PG&E. Further, many of the municipal systems benefit from low-cost federal preference power, and CCSF retail service would be unlikely to reflect the same level of such benefits, due to very limited availability of new preference power. In sum, the numbers presented in this section are not definitive, but instead emphasize the need for the direct analyses specific to CCSF in the rest of this report.

B. Cost Structure Comparison of Munis and IOUs

This section delves into reasons for the muni/IOU rate differences, observed in section 1.A, by making cost-structure comparisons for six muni/IOU-pair cities selected as comparable to SF. This analysis shows that the average cost advantage existing munis enjoy over IOUs in electric-utility systems is explained completely for these six pairs by the higher rates of return on investment that IOUs collect via their rates, as compared to munis.[5] The IOUs' rates of return must cover profits on stockholders' equity and, even more, income taxes on those profits -- two factors for which the munis do not charge their customers. The cost-structure analysis, developed from data in annual reports of munis and IOUs to the federal government, shows that, absent these rate-of-return differences, there are no clear differences in efficiency for these six pairs that allow one to conclude that munis are significantly either more or less efficient in managing operations than IOUs.

Below, this comparison of muni and IOU cost of service is organized into three subsections. First, the methodology of analyzing the cost structure for munis and IOUs is described, and the muni/IOU pairs selected for cost-structure evaluation are reviewed. Second, details of the SMUD/PG&E cost-structure analysis is presented. Finally, summary comparative cost statistics for the six pairs are analyzed. Details of comparisons other than SMUD and PG&E, along with full documentation of the cost-of-service information, is shown in Workpapers 1-B.

1. Cost-Analysis Methodology and Muni/IOU Pairs

The objective of this cost-structure analysis is to determine whether consistent differences in

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[5] In fact, this section shows that the difference in muni and IOU gross costs of capital (due to equity returns and income taxes) are perhaps larger than the muni cost advantage over IOUs. However, the excess of the gross cost of capital difference, as compared to the muni rates advantage, is not enough, especially in view of the small number of pairs in this sample, to infer that IOUs' other costs are systematically significantly on average lower than those of munis. In our view, a reasonable interpretation of the data would be that there may be some small economies of scale for IOUs in a few areas where such economies are inherently clear, but nothing more should be inferred from these data in favor of IOU efficiencies.

productivity can be observed between munis and IOUs that should, in turn, drive assumptions in the SF municipalization cost-benefit analysis. Distribution, customer and administrative costs are thus most important in this cost-structure analysis, because historic production costs and transmission costs of other munis and IOUs are driven in great part by unique factors which are irrelevant to SF municipalization, especially in view of electric-industry restructuring in California. Because the non-income taxes paid by utilities are determined by local policy, analysis of these costs also provides little guidance for SF. Hence, the analysis examines a set of functional cost categories that covers all operating costs for the utilities -- customer services, administrative and general, distribution, transmission, energy production and non-income taxes -- but it focuses on on the first three.

The cost-structure assessment for munis and IOUs is developed through comparing the six cost components for pairs of IOU and muni systems. The IOU/muni neighboring pair framework is used so that differences in business conditions that result in different productivity measures do not distort the analysis. For example, it would be meaningless to compare the cost structure of PG&E with a municipal electric system in Mississippi, because the labor markets, real estate markets, fuel markets and environmental conditions are dramatically different for the two systems. The first four munis, those in Sacramento, Cleveland, Jacksonville and San Antonio, were selected in consultation with the Hetch Hetchy staff as being comparable in scale and nature (including relative access to preference power) to a prospective CCSF municipal system with full retail service. Two additional cities, Los Angeles and Seattle, were selected because they are the two largest electric munis on the West Coast. Of course, each muni/IOU pair has unique circumstances, so the validity and reliability of these comparisons must be qualified. We have tried to incorporate into our comparison data clarifying differences and similarities, which are shown in Workpapers 1-B. In this context, we believe the muni/IOU pair comparisons may be instructive in gauging the productivity of munis versus IOUs in managing distribution systems, customer-related, and administrative and general costs.

2. Cost Structure Comparison for Sacramento (SMUD) and PG&E

The rates comparison for SMUD and PG&E reflects the same pattern of significantly lower

overall rates for the muni relative to the IOU that was noted in the previous section. Figure 1-5 shows PG&E's cost structure for the various cost components based on its pre-tax rate of return on common equity of 17.5%. Figure 1-5 demonstrates that production accounts for almost 60% of PG&E cost, while distribution represents almost 20%. A similar chart in Workpapers 1-B illustrates that, for SMUD, the cost structure is skewed more heavily to production and that the absolute amounts SMUD spends on distribution, administration and general and customer service are significantly lower than the amounts spent by PG&E.

Figure 1-5

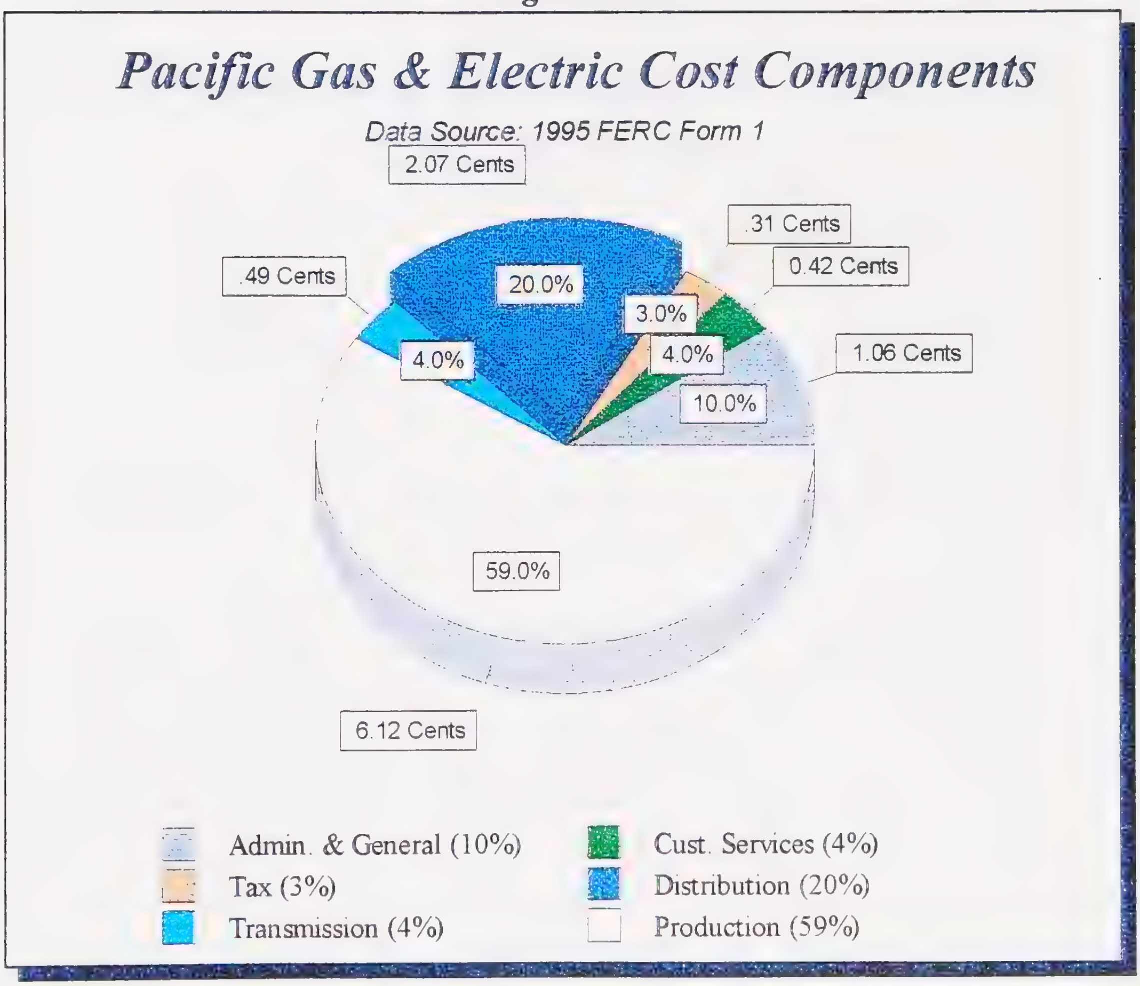
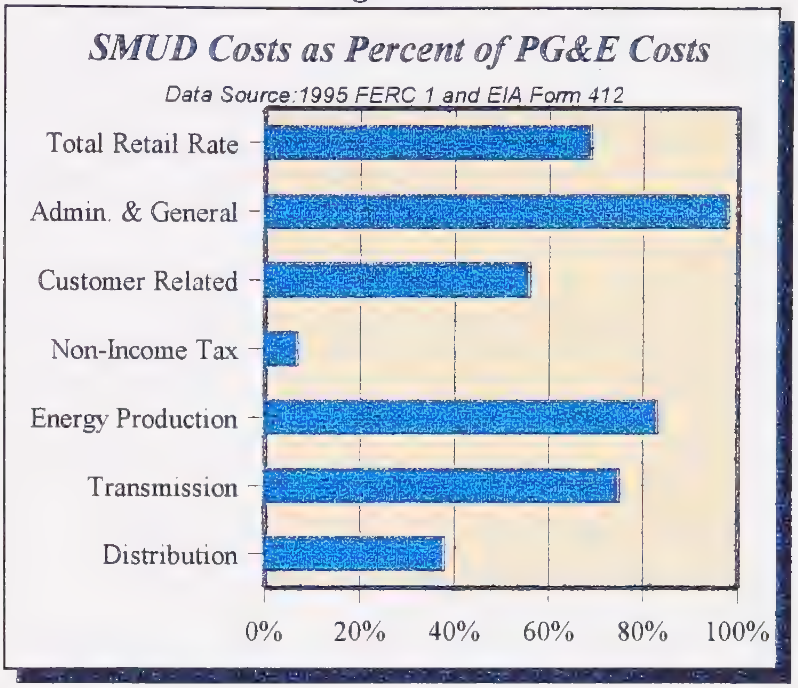


Figure 1-6 summarizes the comparative costs for PG&E and SMUD. Section 1.B.3, below, also presents a cost comparison for this pair, by function, as well as for the other city pairs.

Figure 1-6



3. Cost Structure Comparisons by Function for the Six City Muni/IOU Pairs

The section summarizes our comparisons for the six munis/IOU pairs. In addition to SMUD and PG&E, these comparisons include Cleveland Public Power and Cleveland Electric Illuminating; San Antonio and Texas Utilities; Jacksonville and Florida Power & Light; Seattle and Puget Power Company; and LADWP and SCE. The cost comparison is summarized in Table 1-2, on the next page, on a cost-per-kWhr basis. Workpapers 1-B includes extensive detail for Table 1-2 and shows important cost items on cost-per-customer and cost-per-kWhr bases. In addition, Workpapers 1-B presents cost-of-service differences for each muni/IOU pair.

Table 1-2

Cost of Electricity From Munis & Neighboring IOUs (Cents/kWh)

Utility	*Average Total Rate*	*Taxes (Non-Income)*	*Energy Production Cost*	*Transmission Cost*	*Distribution Cost*	*Customer Related Cost*	*Admin. &Gen. Cost*
Sacramento	7.26	0.02	5.10	0.36	0.78	0.59	0.41
Pacific Gas & Electric	10.47	0.31	6.12	0.48	2.07	1.06	0.42
Cleveland Public	7.85	-	4.24	0.61	2.18	0.62	0.19
Cleveland Elec. (IOU)	8.62	1.18	5.53	0.38	0.79	0.51	0.23
Jacksonville	6.79	0.69	4.36	0.32	0.77	0.54	0.12
Florida Power & Light	6.98	0.72	4.12	0.29	1.03	0.56	0.26
San Antonio	5.57	0.69	3.42	0.14	0.64	0.59	0.08
Texas Utilities	6.93	0.60	4.37	0.20	0.62	0.40	0.19
Los Angeles W&P	9.47	0.42	5.45	0.38	1.43	1.39	0.40
Southern Cal Edison	10.59	0.29	6.61	0.63	1.57	1.17	0.33
Seattle	3.75	-	1.73	0.28	0.95	0.53	0.26
Puget Power & Light	5.77	0.57	2.79	0.53	1.20	0.48	0.20

For each muni/IOU pair, Table 1-2 shows the average total rate for retail electric service based on 1995 data (from the EIA Form 412 for munis and from the FERC Form 1 for IOUs), as well as a breakdown by functional components: non-income taxes; energy production costs; transmission costs; distribution costs; customer-related costs; and administrative and general (A&G) costs. Table 1-3, on the next page, shows the difference (muni cost, less IOU cost) for each component and for the total rates which are left when the gross cost of capital is deducted from the actual functional cost for each of the two utilities. The raw (actual) figures shown in Table 1-2 are of interest in considering what retail ratepayers can expect to pay, while the adjusted figures in Table 1-3 are useful to compare the relative operating efficiencies of the munis and IOUs.

Table 1-3

Cost of Electricity From Munis & Neighboring IOUs (Cents/kWh)
Non-Cost-of-Capital Related Difference

Utility	Average Total Rate	Taxes (Non-Income)	Energy Production Cost	Transmission Cost	Distribution Cost	Customer Related Cost	Admin. &Gen. Cost
Sacramento	7.26	0.02	5.10	0.36	0.78	0.59	0.41
Pacific Gas & Electric	6.40	0.31	3.44	0.30	1.20	0.72	0.42
Non-Cost of Capital Related Difference	0.86	-0.29	1.66	0.06	-0.42	-0.13	-0.01
Cleveland Public	7.85	-	4.24	0.61	2.18	0.62	0.19
Cleveland Elec. (IOU)	8.57	1.18	5.52	0.37	0.76	0.51	0.23
Non-Cost of Capital Related Difference	-0.72	-1.18	-1.28	0.24	1.42	0.11	-0.04
Jacksonville	6.79	0.69	4.36	0.32	0.77	0.54	0.12
FP& L	4.91	0.72	2.66	0.13	0.66	0.50	0.26
Non-Cost of Capital Related Difference	1.88	-0.03	1.70	0.19	0.11	0.04	-0.14
San Antonio	5.57	0.69	3.42	0.14	0.64	0.59	0.08
Texas Utilities	5.08	0.60	3.39	0.14	0.40	0.35	0.19
Non-Cost of Capital Related Difference	0.49	0.09	0.03	0.00	0.24	0.24	-0.11
Los Angeles W&P	9.47	0.42	5.45	0.38	1.43	1.39	0.40
Southern Cal Edison	7.83	0.29	5.62	0.35	0.37	0.87	0.33
Non-Cost of Capital Related Difference	1.64	0.13	-0.17	0.03	1.06	0.52	0.07
Seattle	3.75	-	1.73	0.28	0.95	0.53	0.26
Puget Power & Light	4.34	0.57	2.21	0.44	0.59	0.32	0.20
Non-Cost of Capital Related Difference	-0.59	-0.57	-0.48	-0.16	0.36	0.21	0.06

C. Municipalizations Attempted Since 1975 in PG&E's Territory

Based on a review of various sources, only one actual attempt -- involving the Hayfork Valley Public Utility District (PUD) -- has been made over the last 20 years to municipalize electric-utility service in the PG&E service area. As discussed below, Hayfork Valley's attempt was only partly opposed by PG&E, and it met with mixed success. A second "municipalization" was the creation of the Tuolomne County Public Power Agency (PPA), a specialized utility -- i.e., an entity that is not really a retail muni, but has some attributes of one and provides a very limited range of service to a very limited customer base. Although these two cases are not at all comparable to SF, as shown below, we discuss them to fulfill the purpose of this sub-task: to glean from their experiences any guidance useful to SF. Other municipalization proposals have been made by various parties, not actually resulting in significant action. The farthest these proposals have gotten was reached this year in the 26 March primary election in Calaveras County, as the Calaveras County Citizens for Lower Electric Rates (CCLER) mounted a local initiative to the ballot, proposing to municipalize PG&E electric-utility operations in their area. According to their account, they were outspent on publicity 40-1 by PG&E and lost at the ballot box by a margin of 3-1.

1. Hayfork Valley Public Utility District

In 1983, a ballot proposition such as that in Calaveras County did succeed in Hayfork Valley. According to court filings, a 1993 bond-issue prospectus from the Trinity County Public Utilities District (PUD), and our interviews with representatives of both sides, PG&E had, in fact, already been discussing with Trinity County, in which Hayfork Valley is located, the sale of its distribution system there because the area was very costly for PG&E to serve. However, some Hayfork Valley residents became impatient with the progress of those negotiations and proceeded on their own. In 1984, the newly formed district's board initiated the municipalization process, seeking to serve only the most populous part of the area (leaving high-cost, low-population areas to PG&E); trying to take only the minimum facilities, other property and franchise rights needed; and leaving PG&E various

options to serve the adjoining areas. The total customer base acquired by the Hayfork Valley PUD was only 724 meters, or about one-fifth of one percent of the total meters in SF, and it was greatly residential, with few commercial and no industrial customers.

The Hayfork Valley PUD left PG&E the high-cost area and limited rights and facilities, and the initial proposals of the Hayfork Valley PUD would have cost PG&E relatively very high physical severance and distribution-system reconfiguration costs. As a result, PG&E tied up the Hayfork Valley PUD in court over most of the 1980s, exhausting Hayfork Valley's ability to pursue the matter. However, in 1982, some other portions of Trinity County, previously served by PG&E's then-neighbor, CP National, had created the Trinity County PUD, with 2,189 meters. Because it was larger and had not run into such problems in its formation, the Trinity County PUD was able to absorb the Hayfork Valley PUD. Trinity County PUD was willing and able to negotiate terms satisfactory to PG&E that allowed the IOU to cleanly turn over a complete, high-cost (low-profit) service area and not have to continue service to its worst portions or otherwise face residual problems from the transaction. Thus, the Trinity County PUD was able to arrive at a comprehensive agreement and stipulations that resulted in a recently completed $8.2-million sale by PG&E at somewhat below the standard replacement-cost formula discussed in chapter 2. It is not possible to be more precise than this about the valuation basis, because the value was determined in a settlement, which does not state whether it represents an income-based valuation or some other approach.

Today, the Trinity County PUD serves roughly 6,500 meters and is the exclusive provider of service in its area, owning all the transmission and distribution facilities it uses to serve, as the sole provider, the 65% of the county north of the South Fork of the Trinity River. It purchases its power supply from the federal Western Area Power Administration (WAPA) pursuant to a first preference right granted to public agencies in the county pursuant to the 1995 federal Trinity River Act. It is not meaningful to make an allocation of the approximately 15 full-time employees to the areas formerly served by PG&E, which are varied in their nature and greatly different from urban SF, or otherwise to compare this municipalization to SF's situation. However, on a typical-bill basis, rates to the former PG&E service areas were expected to be about 20% below PG&E's former levels, according

to an 8 June 1993 bond prospectus issued by the Trinity County PUD. The differing rate structures of PG&E and the PUD make impractical a definitive actual rate comparison for this project -- which would be of little value, anyway, given the differences between the Trinity County and SF situations.

2. Tuolomne County Public Power Agency

The American Public Power Association (APPA) reports that in 1982 the Tuolomne County PPA was formed in the PG&E service area, taking 215 meters. Perhaps due to its small size, this PPA does not show up in summary records released by the federal Energy Information Administration, although it does purchase preference power from WAPA. According to Dominic Salluce of this PPA (telephone call by Grace Reyes 4 October 1996), this PPA is ancillary to a water utility operated by the county, which it bought from PG&E because the IOU's cost of service would have been so high as a result of CPUC directives concerning it that PG&E elected to sell the water service. The PPA provides service now to 224 commercial customers -- less than one-tenth of one percent of SF's total. Moreover, it uses distribution lines leased from PG&E; however, due to PG&E's willingness (desire) to help its formation (to unload the water-utility obligation) and PG&E's stated unwillingness to assist CCSF in a similar manner, the lease arrangement would not be available to CCSF. In sum, it is not comparable to SF in any way to merit further investigation.

D. Success Factors, Obstacles and Recurring Problems for Munis

1. In Establishing a Municipal Electric Utility

a. Voter Support and Public Agency Staying Power Versus Resistance, Litigation and Delay

Our review here of the very limited recent municipal electric utility formation experience in California shows that strong voter support, as well as strong commitment and staying power of the

municipalizing entity, are absolutely essential success factors -- because the delay, litigation and other hurdles involved are major recurring obstacles. APPA's "Straight Answers to False Charges Against Public Power" emphasizes this point (page 18 et seq.). The 1996 experience of Calaveras Citizens for Lower Electric Rates, losing a municipalization referendum 3-1 and being outspent 40-1 in the process, shows the need for strong public support. It took Hayfork Valley and Trinity County about a dozen years from the start to the end of the process, even though the municipal utilities were set up early in that time frame. This experience shows the need for strong commitment and staying power of the municipalizing entity; indeed, Hayfork Valley did not have, by itself, the resources needed to stay the course without combining with the Trinity County PUD, as discussed above. Another measure of the difficulty is that, while APPA lists 35 "Publicly Owned Electric Utilities Established (1980-1995)", the size range for them is from one to 15,845 meters, with only six new entities being larger than the present Trinity County PUD. On the other hand, APPA reports that various large cities (e.g., El Paso, Toledo, Albuquerque, Chicago and New Orleans) have studied electric municipalization in the last decade -- but none have followed through.

b. Physical Severance Damage, Distribution-System Reconfiguration and Local Power Plants Providing Area Load Support

Physical severance damage and the need to reconfigure the IOU's system or operations as a result of municipalization is a significant factor usually only for small utilities such as Hayfork Valley. Our assessments in chapter 2 show that this item is small for SF. However, it does suggest a related issue which arises for SF, despite its size, due to the unusual geography and electric-system topology of SF and the Peninsula. That issue in San Francisco's case is whether municipalization of the SF electric distribution system would cause a diminution in value of the Hunters Point and Potrero power plants in SF owned by PG&E if CCSF chose not to acquire them. PG&E could argue that, if there were such a diminution, then The City would owe PG&E compensation for that loss in value. On the other hand, the taking of the SF distribution system, without those two power plants, also at first raises questions of system reliability problems for the condemnor -- not for the condemnee, as was the case for Hayfork Valley. The question from this perspective is whether CCSF may need the two

power plants to provide for the reliability of an SF muni utility. Taking the two plants would, of course, resolve the problem of any possible diminished value in PG&E's hands or reliability concerns that CCSF might have, but it would also be quite expensive. In any event, this issue merited and received investigation here. Our results showed, however, that these concerns are generally obviated by the particular terms of the AB 1890 restructuring of California's electric business, which both assures PG&E of cost recovery for these two plants and assures CCSF of reliability and ancillary services support from the grid (services for which CCSF would pay cost-based fees).

c. Distribution System Valuation: Replacement v. Original Costs; Depreciation Methods; and Income (Economic) Analyses

Additionally on the formation aspect of municipal electric utilities, almost always the biggest factor -- one that may be a success factor or major obstacle, depending on how it is resolved, and thus is always a recurring problem in municipal condemnation -- is the valuation method and its detailed application to the facilities and other property taken. PG&E's opening brief on appeal in the Hayfork Valley case focused extensively on these matters, and in almost every electric municipalization initiative, their resolution affects the rates significantly. As we will show in the next chapter (and as that brief noted), the basic choice is between formulas based on replacement costs of the assets and traditional economic ("income" or "present-worth") analysis. The resolution of this issue by a court and jury may lead to an extremely wide range of outcomes. Another aspect that the arguments in condemnation cases point up is that, even when parties agree on one of these two methods in principle, their implementations of it may yield also very wide valuation differences. In short, this item in most cases is so large and subject to such uncertainty that it usually dominates rate impacts.

In addition to the two basic approaches, the Hayfork Valley appeal demonstrates that there is a significant secondary issue: the depreciation method used, especially if a replacement-cost formula is employed. The choices here are between traditional "straight-line" accounting depreciation and "economic" (or "sinking-fund") methods. Arguments can be made on both sides of the depreciation issue, and it makes perhaps 70% additional difference beyond that for the choice between the income

and straight-line valuation formulas -- so, it is a very important valuation factor, as we will show. In sum, the price to be paid by the acquiring muni is a major issue, and it is determined mainly by the valuation method and the details of that method.

d. Stranded Costs, Bypass and "Competition Transition Charges" (CTCs)

Before turning to post-formation factors, it is important to note one valuation factor that has in recent years lurked around condemnations and valuations, and which has come to the fore in the restructuring and reregulation over the last year of the electric-utility business: stranded costs. This matter has been raised in municipalizations attempted in other states, and it has arisen in the valuation of distribution systems annexed by California municipals, as discussed in chapter 2, but it has not arisen in new municipalizations in the last decade in California because there have not been any. We understand it was raised, though, in the context of the unsuccessful Calaveras initiative this year.

Stranded costs include the reduction in value of utility assets as a result of the loss of markets in which their original costs (historic costs or book values) can be recovered. Thus, when a muni takes a distribution system from an IOU, it may diminish the value of the IOU's generating and other assets that it doesn't take. This fact is particularly problematic when the IOU owns generating resources that have become uneconomic, for then the muni is helping the IOU's former customers "bypass" (avoid) the cost-based, but higher-than-market rates that U.S. monopoly-franchise and regulation policies allow IOUs to charge to ratepayers. Full cost recovery by the IOU may be part of the "regulatory bargain" (i.e., the policy IOUs get cost-based rates in exchange for being regulated) and the IOU would not, under bypass, get what it argues is its due.

As discussed in chapters 2 and 3, stranded costs for PG&E and other California IOU electrics have been addressed by AB 1890 and federal regulation (FERC Order No. 888, 1996) in ways that tend to remove a traditional advantage of municipalization. Thus, traditionally, a major potential benefit of municipalization was that it might allow ratepayers of the new muni to escape

uneconomically high costs passed on to them by some IOUs -- such as PG&E's costs for its Diablo Canyon plant and its high costs under certain power purchase contracts. The IOUs, of course, argued (successfully in major cases) that, if they were deprived of the opportunity to collect these costs from the departing ratepayers through rates, then they should get them through higher valuations for the condemned distribution system. In any event, AB 1890 allows them to prevail extensively in all cases and to remove from the table this advantage of municipalization. It allows the IOUs to collect large parts of their stranded costs through the year 2001 (i.e., before municipalization could happen) and to continue collecting them even in later years, despite any municipalization that might occur. The exaction of these stranded costs is done by allowing the IOUs to collect "competition transition charges" (CTCs) as a condition of munis or any customer getting access to the grid transmission services, which all need in order to receive electric service.

The upshot of all of this for this study is that we have given full consideration to this traditional major factor supporting municipalization which emerges from review of other munis and municipalizations. However, our analysis must and does reflect its current status by including CTC charges for both the muni and BAU scenarios in like amounts in chapters 3 and 4. Had this study been done before mid-1996, when the resolution of this issue was still in doubt (before the legislature's act and Governor's signature), then it would have focused extensively on possible benefits from this potential bypass factor. As a consequence of the history surrounding this factor, we examined it closely, but found no escape from collection of the stranded costs through the CTCs.

2. *Operating the Municipal Electric Utility Once It Is Established*

The comparison in this chapter of IOU and muni electric rates by utility and category shows, however, that post-formation factors are also very important to the analysis. In the sub-sections below, we discuss these factors in the groups into which they naturally divide.

a. Gross Cost of Capital: Full Leveraging & Income-Tax Exemption

A final factor that weighs in the decision to municipalize is one that constitutes perhaps the major success factor to munis that deliver electric-utility service economically to their ratepayers: the lower gross cost of capital for public-agency power than for IOUs. This factor, like the valuation basis, plays an inherent role in any municialization. For this reason, we reflected it in the city-pair comparisons in this chapter by adjusting it out to yield a true comparison of the other factors. As explained in the summary to this chapter at page 1-2, it results from two factors, leverage and income-tax avoidance. By relying on its possible recourse to general tax revenues (i.e., putting the City's taxpayers at risk in a manner similar to that in which IOU stockholders are), a publicly owned entity can finance its utility operations completely with debt and does not need any equity. (In the alternative, local taxpayers supply an equity component and carry some residual risk, but get no return on their equity.) This fully leveraged financing yields lower costs to ratepayers and taxpayers as long as things go normally or well, but as the WPPSS cost overruns and bankruptcies showed (discussed in chapter 4), it costs them when things go very badly.

The benefit of the exemption from income taxes, like the leveraging effects, gets passed on to muni ratepayers in the form of rates reduced from what they would be if the muni had to pay income taxes. The income-tax revenues are lost to the federal and state treasuries, resulting in either reduced public-sector spending, higher taxes on other people and firms, or both. But the balance for ratepayers from municipalization clearly lies to one side, because their electric rate savings will greatly exceed their increased other taxes or reduced state and federal spending benefits. In sum, the joint effect of these two factors is to lower the gross cost of capital needed to finance utility ownership and operations from nearly 13.58% (current levels for PG&E, as shown in chapter two) to about 7.5% (the current muni level, as also shown there). Since more then two-thirds of this effect is due to income-tax exemption, if the corporate income tax were to be significantly reduced or completely replaced by other revenue sources, then this advantage ("success factor") would be greatly reduced; if it were to be increased, then this advantage would increase.

b. Energy Supply Costs: Preference Power, Nukes, Purchase Power and QFs

Another traditional success factor for some muni electric utilities has been cheap energy supply via "preference power" allocated to public agencies from federal projects and sold at low rates. The muni/IOU-pair comparisons show this can be a factor, although it is not usually a large one. Moreover, because all significant amounts (relative to SF's needs) of such energy is already allocated (in the West by both WAPA and the Bonneville Power Administration), and very few new power resources are being developed by the federal government, this is not likely to a material factor for The City, as discussed in chapter 3. Another recurring factor that has led to success or failure for muni electric utilities is ownership of nuclear generating plant interests; it also would not apply to SF because none are being built in California or will be built in the foreseeable future.

However, other experience of the muni electric utilities reviewed here may apply to SF in the power-supply resources area. First, muni systems tend to be highly dependent on purchased power, historically in part because of limited ability to build power plants inside their borders or otherwise accessible to their transmission grids. This factor is now obviated by open-access transmission rules; in the newly restructured/reregulated electric-utility environment, purchase dependency will not be an issue. Also, California's publicly owned electric utilities in general have purchased much less of their energy from QFs and other "alternative energy" resources than have the state's IOUs (typically, about 2% for munis, versus one-third for the IOUs). On the other hand, our research has revealed that much of the two IOU's record is attributable to the mandates of the CPUC, and much of the munis' lack of contracting for such power resulted from their low energy-supply costs. As the restructuring toward a competitive market in electricity in California proceeds, differences due to these two factors will recede, and the performance of munis and IOUs on QF and alternatives support should tend to converge at least somewhat. Ultimately, of course, if CCSF elects the muni electric option, the level of such purchases would be a policy issue for The City to resolve for itself.

c. Size and Scope Economies, and Relative Muni/IOU Operating Efficiencies

Two other related areas which the muni/IOU-pair comparisons show may potentially be either success factors or obstacles or recurring problems are as defined at page 1-5: 1) size and scope economies; and 2) questions of relative operating efficiency and costs to ratepayers of municipal and IOU electric-utility operations. Many economies of scale, or size effects, are probably exhausted at only the level of a city the size of SF, as discussed in section 1.B, but a few may not be. Economies of scope -- resulting from combining electric operations with other public-service functions -- depend on the combination possibilities: thus, PG&E provides gas utility service, as well as electric-utility service; but SF could combine electric-utility service with street and sewer services. It is unclear *a priori* which way the balance tilts in SF; if scope economies favor municipalization, it is not clear whether they offset the loss of PG&E's natural economies of scale.

Likewise, the muni/IOU-pair cost figures in section 1.B suggest that municipal provision may not be as efficient as IOU provision for distribution services, when gross-cost-of-capital effects are factored out -- but the SMUD/PG&E comparison provides a striking counter-example. On balance, these items -- or at least the economies of scale and of ultimate operating efficiency -- may well be obstacles or even recurring problems, but the data show there are possible success factors here, too. In any event, they show the importance for both munis and IOUs of strong and effective management; it can make or break munis and IOUs. These issues are addressed in section 3.B.

d. Rate Design, Area-Cost Averaging, Taxes and Subsidies

Some related factors are not immediately apparent on the face of the data in this chapter, but instead underlie much of the muni/IOU economic comparison and are still quite pertinent considerations in the decision to municipalize. One factor is that IOUs, almost without exception, nowadays practice area-cost averaging -- i.e., charging the same rates to customers of a given class

whether they're located in the foothills, in a suburban tract or downtown in the central city. PG&E has in recent years made extensive studies examining the distribution and transmission cost differentials to serve various areas, developing data that would provide a basis for area-rate differentiation based on cost differences. However, its efforts have not satisfied a number of parties, and the CPUC, while interested in and supportive of this work, has not yet indicated an inclination to use it directly for local-area cost-based rates. In fact, the CPUC has a long history of requiring area cost averaging. As chapters 2 and 4 here show, this factor (development of area-specific distribution rates) is a key potential obstacle for SF municipalization if the CPUC were to change its policies and a success factor if not.

On the other side of the coin, some municipalities use their electric-utility operations as revenue sources for the general fund -- much like non-muni cities place utility taxes on IOU service. But doing this means either that other municipal taxes are reduced, or that municipal services are increased, or both. Hence, the analysis should be done, as it is in chapter 4, as if no surplus were generated to assess only the pure comparative electric utility costs for the muni and IOU scenarios.

None of these considerations appear to raise obstacles, let alone recurring problems, and some of them (such as maintaining area-cost averaging) are potential success factors. In any event, they are important aspects of the municipalization decision we will seek to clarify in coming chapters, just as we will do so for the other considerations discussed here.

Conclusion of Chapter 1

Our muni/IOU rate comparisons in section 1.A show that munis charge lower electric rates. The section 1.B muni/IOU pair comparisons show that the muni overall rate advantage is completely due to munis' lower gross costs of capital, especially the munis' exemption from income taxes -- for existing munis and IOUs. Our review of municipalization efforts in section 1.C shows that, whatever the rate and cost facts between existing munis and IOUs, a major issue in deciding whether to

municipalize is something else: the valuation in a court condemnation action of the property to be taken, which is so large and uncertain as to seem to dominate the decision if it is made only on the basis of comparative rates. The success factors, obstacles and recurring problems discussion in section 1.D also highlights this point and especially the role of income taxes in setting electric utility rates. Hence, it is appropriate that task 2, discussed in the next chapter, focuses on valuation first. The rest of chapter 2 and chapter 3 address the other cost factors, and all of them, especially income taxes, are brought together in chapters 4-6.

CHAPTER 2: Cost of Acquiring PG&E's SF Electric Distribution System

Overview and Summary of Chapter 2

Introduction, Purpose and Scope

If the City and County of San Francisco ultimately decides to create a municipal electric utility, it will do so by initiating a court action, called "condemnation", in which it seeks a court order allowing it to take from PG&E the electric-distribution system and related assets[1] used to provide electric service to SF (here "the SF distribution system"). As part of the condemnation case, the court will set the compensation that CCSF must pay to PG&E for taking its properties. As shown in chapter 4, we find that the cost of acquiring the distribution system and related assets is one of the two most important variables that will determine whether municipalization of SF electric service will raise or lower electric utility rates for SF ratepayers. A low acquisition cost increases the probability that a municipal electric-utility will produce lower rates. Conversely, the higher the acquisition cost is, the lower the probability is that creating a municipal electric utility will yield lower rates.

Before the restructuring[2] of California's electric utility industry, the avoidance of PG&E's high cost of generating and purchasing electricity through municipalization could have played perhaps a very important role than the acquisition cost of the SF distribution system in an analysis of the potential rate impacts of municipalization. However, as discussed in chapter 3, the recent adoption of policies by the Federal Energy Regulatory Commission (FERC) and the California Public Utilities

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[1] PG&E assets that are directly related to the distribution of electricity within the CCSF include the distribution system itself, an underground high-voltage system and the Martin Substation.

[2] The term "restructuring" refers to the actions taken in 1995 and 1996 by FERC and California's PUC, Legislature and Governor to create market competition in electricity generation.

Commission (CPUC) to encourage development of a competitive electricity supply market[3] and the enactment of Assembly Bill (AB) 1890 to restructure the electric utility industry in California are expected to reduce the cost of electricity supply to the electric ratepayers in SF over the next five years to market-based levels. By 2002, the earliest date we estimate that an electric municipal utility could be ready to serve San Franciscans, the consensus forecast (reflected, for example, in California Energy Commission forecasts) is that there will be virtually no difference in the costs of electricity supply to ratepayers, whether or not a municipal electric utility is created in SF. Therefore, the cost of acquiring the SF distribution system is now on of the two key variables determining whether there are significant rate impacts of municipalization.

Three factors will mainly determine CCSF's cost to acquire PG&E's SF distribution system: 1) the valuation methods that a court allows to be presented to a jury in a condemnation case by The City against PG&E; 2) particulars of the application of the adopted method to the SF electric system assets; and 3) the date the court adopts for determining the value for the SF the electric-system assets. This chapter reviews valuation methods that a court may allow in the condemnation case (section 2.A) to arrive at an estimated range and base-case value for the cost of acquiring the SF distribution system. Following a description of PG&E's SF distribution system assets (section 2.B), we document our application of the methods of valuation to develop our estimate of the PG&E's distribution assets within SF (section 2.C). The valuation results based on the earliest feasible date are then carried forward to chapter 4, where overall rate impacts and net benefits or costs of municipalization are calculated and which shows that changes in the start date don't change the economic analysis.

Results of Analysis

Figure 2-1, on the next page, graphically presents the results of our analysis of the estimated range of values for the cost of acquiring PG&E's San Francisco electric distributionsystem and related assets as of year-end 2001.

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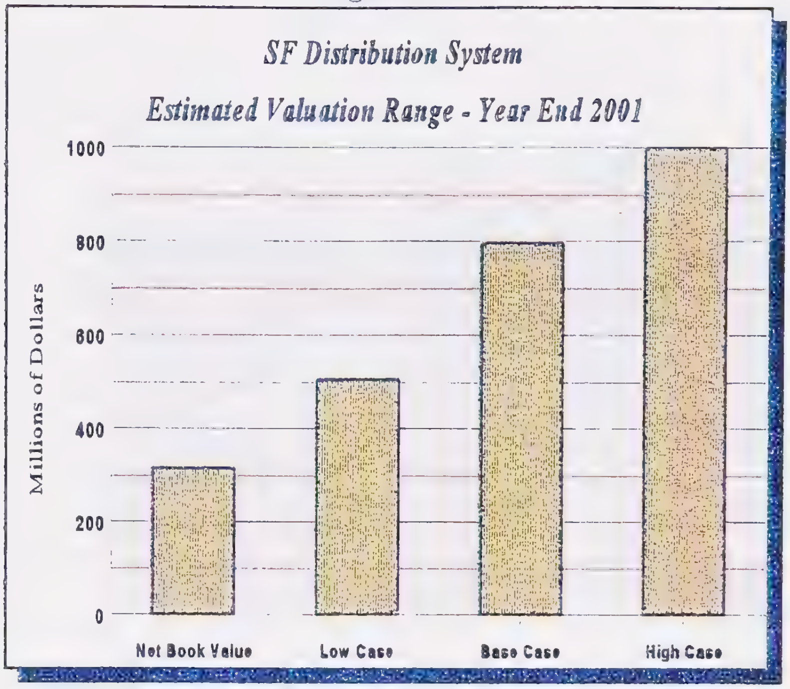
[3] The term "electricity supply", as used herein, refers to the cost of generating and purchasing electricity and transmitting that electricity to load centers such as SF.

Figure 2-1



The valuation methods used to arrive at these estimates, which are explained in detail in this chapter, are as follows:

- *Net Book Value* **(NBV)** of PG&E's SF distribution system represents original cost, less accumulated book depreciation **(OCLD)**. We estimate it at $315-million (year-end 2001). This reference point is not within the reasonable valuation range, as discussed below.

- *Low Case* - represents the value of PG&E's SF distribution system produced by the capitalization of net income method **(Income Capitalization)**, and we estimate it to be $505-million as of year-end 2001.

- *Base Case* - is the valuation produced by the Reproduction Cost New Less Straight-Line Depreciation method **(RCL-SL)**. As of year-end 2001, we estimate that the RCL-SL value of PG&E's SF distribution system will be $795-million.

- ***High Case*** - represents the value of PG&E's SF distribution system produced by Reproduction Cost New Less Sinking-Fund Depreciation (**RCL-SF**) method of valuation. As of year-end 2001 we estimate this value at $999-million, but there is also evidence PG&E may present testimony putting it even higher.

To asess the range of potential and likely valuation outcomes and determine which valuation methods are likely to be allowed or adopted by a court in a condemnation proceeding, we reviewed precedent from condemnation proceedings in California, other states and the federal courts. Our analysis concludes that the cost of acquiring PG&E's SF distribution in the year 2001 will *most likely* be bounded by the values produced by the Income Capitalization method of valuation ($505-million) and the RCL-SF method ($999-million), with a representative intermediate figure being the RCL-SL method ($795-million). Because the value of the PG&E distribution system will be determined in litigation, we cannot rule out the possibility that a lower or higher value could result. In calculating municipalization rate impacts and overall costs and benefits presented in chapter 4, we have therefore included the results produced by all four valuation methods.

The NBV case is, in our view, a boundary case which is very unlikely to be realized. The Income Capitalization method is a realistic "Low Cost" value, the RCL-SF is a realistic "High Cost" value, and the RCL-SL is our "Base Case" value. As discussed in section 2.A, we believe that the base-case figure is representative, but that other intermediate values are possible. On balance, it is perhaps somewhat more likely that the value determined in a condemnation case will be lower than the base-case value, rather than higher. Hence, our base case has a touch of analytic and planning conservatism (i.e., a slight margin for error on the high side) built into it.

Risk Factor

The cost of acquiring the PG&E distribution system is one of the two most important factors in assessing the rate impacts of municipalization. ETAG has prepared its estimates of the possible range of this cost based on the best publicly available cost data. However, these data do not include

a specific detailed accounting, inspection or physical inventory of PG&E's distribution assets that serve only SF. Determining an accurate historic cost and reproduction value will require a time-consuming and costly inventory of all PG&E transmission and distribution assets that serve SF. This effort should perhaps be undertaken if the CCSF elects to conduct an expanded feasibility study on the merits of municipalization or simply decides to proceed with municipalization.

Organization of Chapter 2

The rest of this chapter provides a detailed explanation of the methods and analysis used to arrive at the conclusions presented above on valuation of PG&E's SF electric-distribution system. Because this chapter deals with highly technical issues and terms unique to the electric-utility industry, we attempted to simplify the presentation of our analysis, but some technical material had to be retained in the text because it is essential to resolving this important issue, and therefore merits full airing. Section 2.A presents our analysis of the approaches to valuing utility assets and likely condemnation valuation results. Section 2.B presents a description of PG&E's electric distribution system serving SF. Sections 2.C, 2.D and 2.E document ETAG's valuation of PG&E's SF electric distribution system. Section 2.F addresses cost of capital, condition of the SF distribution assets, and miscellaneous other task 2 topics. Details of calculations and supporting schedules are contained in a separate document (Workpapers). In this chapter, we reference these workpapers as "(WP-2.X)" for readers reviewing the supporting numerical details, where X is the section designation.

A. Valuation Methods

This section is, by its nature, technical. If its subject matter were not central to the prospects for municipalization of electric service in SF, we would move it to an appendix and only summarize its conclusions here. Casual readers may want to read the next two paragraphs and skim the rest of this section or merely skip to its conclusion in sub-section 2.A.3 (beginning at page 2-19) before going on to the next section.

There are five basic widely recognized approaches to valuing assets of utility systems in condemnation proceedings and in voluntary transactions:

1. ***RCLD:*** Reproduction Cost New Less Depreciation and Replacement Cost Net of Percent Condition, which are formally distinct, but related, and which we treat as one;[4]
2. ***OCLD:*** Original Cost Less Depreciation, or Historic Cost Less Depreciation (HCLD), or Net Book Value (NBV), or just "book value";
3. ***Income:*** Income capitalization methods, or capitalization of future net cash flows (income) from ownership and operation of the utility system;
4. ***Market:*** Market surveys of sales of comparable distribution systems -- which are not possible here because there have been no comparable sales; and
5. ***Other:*** Methods based on equity and debt components of the current ownership's financing -- which are not widely used and not used here because PG&E's SF system is a small part of its diversified and complex holdings, and thus it's speculative at best to assign specific financing to the SF electric system.

Thus, because we are dealing with a major electric-utility distribution system embedded in the integrated regional system of a huge electric IOU, only the RCLD, OCLD and Income basic methods are available here. (If we were considering, say, a water company, the market and debt or equity methods might well be practical. They are noted here because the scope of work for this project emphasized that the review of this vital issue should be thorough and complete.)

Some other terms needed to understand these valuations include "going concern value" (GCV, an estimate of the value added by the business's organization and continued operation to the

[4] The difference goes to whether one would reproduce the existing facilities with exactly the same design -- or whether technical progress or changes in market conditions dictate that they be replaced with newer designs or substitute facilities. Because change in electric-utility distribution systems is far slower than, say, that in personal computers, the formal distinction is usually ignored for electric-distribution valuations such as these.

stand-alone value of the assets taken separately) and "physical severance" (PS, the cost of making physical changes to the utility system that must be made to accommodate the taking and safe operation by the new owner and the continued economic and safe operation of the IOU's retained system). GCV is a factor that traditionally is associated with RCLD and perhaps with OCLD, but which is usually redundant to a capitalized income value (which, in correct applications, includes the intangible value of the organization and continued operation, not just the stand-alone asset value). By its nature, PS must be added to all methods. A final issue, specific to the RCLD and OCLD methods, is the choice among depreciation methods, as between straight-line (SL, book or accounting) methods and economic (or "sinking-fund" or SF) methods. These items -- GCV, PS and depreciation methods -- are discussed *infra* in connection with review of the basic methods.

1. Valuation: Economic and Public-Policy View

Economic theory, by itself, cannot determine a compensation requirement or standard. Thus, the starting point for the economic analysis is the legal principle that compensation is required (per the Fifth Amendment to the U.S. Constitution, in the "takings" clause), and that the point is to fully compensate the condemnee -- in this case PG&E -- for the property taken for public use, but at the same time to pay no more than full compensation. The basic question is: "What would the property be worth (in the sense of full compensation) to a prudent and efficient owner standing in PG&E's shoes?" Most economists would answer that the best estimate would be a market price, if there is a functioning market in the property being taken. Thus, the first choice would be a market survey of the sales prices in voluntary transactions of comparable assets. As noted above, there have been no comparable sales, and thus we must seek an alternative method in the area economists call the dark jungles of second best. In matters of second best, there is often a range of opinion and disagreement among economists on basic approaches, as well as implementation details. Coupled with the fact that the valuation matter is decided in a legal context (discussed in the next subsection), this debate gives rise to significant uncertainty regarding the final outcome value.

a. OCLD

Of the three remaining methods (OCLD, RCLD and income approaches), the easiest one to address is OCLD, per se (as distinct from OCLD as a result of an income approach, as discussed below). Accounting book values for particular assets based on historic costs, as such, are not good indicators of current value because they do not reflect changes in the function, cost and value of assets since the time the historic costs were paid. In fact, they may not even reflect the economic value at the time the asset is placed into service, because an economic decision to purchase or install an asset is made if its cost is less than or equal to its value; thus, the value may exceed the cost from the start. Even within the constraints of generally accepted accounting principles (GAAP), book values may be significantly and systematically less than current economic value in an asset's present and expected use and business context. In fact, the accounting profession recognizes that net book values do not reflect economic values, even for an entire business, and it has developed alternative accounting methods to more accurately reflect real asset values in the accounting books and records of firms.[5]

Further, because GAAP provides particular exemptions under certain circumstances for regulated firms, utility book values -- i.e., OCLD for specific assets -- may understate or overstate the economic value of those assets. In particular, accounting values fail to reflect residual (or appreciation) values of assets at the end of their nominal useful lives, and they fail to reflect residual values those assets may have to their IOU owners in the event they are removed from the control of regulation. As a result, it is nearly universally accepted now by economists, other valuation practitioners and public-policy analysts that OCLD, per se, is not a useful estimate of the economic value (in condemnation, voluntary sales or otherwise) of assets. Those who argue for it almost always support it as a result of an "income" analysis, to which we now turn.

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[5] The accounting principle of conservatism requires that the books reflect either net book cost or market value, whichever is lower; thus, accounting values hewing to this standard may systematically understate economic values of assets, but they won't overstate them, in most cases, except for temporary downward ratchets in values of assets such as real estate.

b. Income Capitalization Analyses

An income analysis is based on the fundamental principle that the value of an asset is the present value at an appropriate discount rate of the maximum expected stream of net incomes it allows its owner to generate over its service life. Projecting net revenues raises substantial issues of interpretation and practice about which there is wide disagreement, and it requires forecasts of future values, which introduce inherent uncertainty into the estimate -- although this is not as serious a problem as are the methodological issues. This can be a completely reasonable method, but one using it must be careful to assure that one has projected net revenues from all sources or components, and not overlook any source or component, as two key examples demonstrate below. And one must be sure to project only net revenues (although errors in this regard are infrequent).

A key example of the methodological problems for income capitalization arises as a result of the nearly universal practice -- long required of California IOUs by the CPUC -- of area-cost averaging in utility ratemaking. Under this practice, utility rates are set at the same levels for all customers of a given class in a utility's service area, regardless of whether the cost of providing service in their area is above, below or at the average cost on the system. As a consequence of this practice, when a municipality in a low-cost area -- which our valuation results show SF is[6] -- decides to take in condemnation the local part of the IOU's system, it will acquire assets that are actually earning for the IOU higher rates of return on investment in them than the IOU's allowed rate of return on its total investment (and this fact is fully consistent with basic principles of utility regulation). For this reason, it is improper (and the results are incorrect) to project, as some practitioners do, total cash flows as only the sum of the system-wide average "profit" (or return on investment) from the asset and its depreciation (as if the only revenues associated with the asset's use in utility service are the sum of the operating costs associated directly with those assets, their

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[6]That is, in applying the capitalized-net-income method to the SF distribution system, the value of that system is based on the net book value and average operating and maintenance cost of the whole PG&E electric distribution system, because those factors help set the rates PG&E's SF ratepayers pay. Comparison in Figure 2-4, *infra*, of SF and system-wide NBVs per customer shows that the latter is higher, and comparison in section 3.B.1 of operating and maintenance costs of the SF and system-wide O&M costs show the latter is again higher. Hence, for distribution, SF is a low-cost area to serve.

depreciation and a return on them at the IOU's overall allowed rate of return). A proper income analysis must include all net revenues from the area taken which is served by the assets taken. Users of the system-average rate of return and stand-alone asset value to project these net revenues may claim that IOUs will always be allowed by their regulators to make up in their remaining service areas the revenues above their allowed rates of return that they lose by losing a municipalized area -- but it isn't so, at least in California, and thus this claim will also not rescue this approach from error.[7] Also, bypass of an IOU's expensive energy supply will not help bypassing customers avoid area-cost averaging for distribution costs, but only for energy-supply costs.

The second key methodological problem arises with the recognition of "stranded costs," recognition which has become nearly universal in recent years as the electric-utility industry is restructured and reregulated, and which has become prominent in California electric-utility matters. The existence of stranded costs (by definition, costs that are higher than those that could be recovered in a competitive market) highlights the fact that, before California's electric-industry restructuring, a major part of the value to an IOU of its distribution system was that it provided a market (customer base) for energy from power plants the IOU also owns. Thus, if part of an IOU's distribution system and customer base was taken, so was part of its market for its power plants' output, and they were thereby reduced in value. IOUs argued that it followed that valuation of the distribution system should reflect stranded costs that would have been recovered through it as a marketing medium and from the customers also taken by the muni (as well as covering the direct costs of the distribution system) if the condemnee were to be fully compensated for the economic damage from the taking. IOUs have prevailed in valuations with this view in major cases (e.g., creation of SMUD in 1942, the last major California electric municipalization); it has also added support to RCLD-based estimates and kept figures high that were agreed to in litigation and voluntary transactions. In any

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[7] Decisions of the CPUC's predecessor, the California Railroad Commission, on ratemaking treatment of IOU asset sales to municipal utilities have set the standard for ratemaking -- also observed by the civil courts for valuation, as explained in the next subsection -- that RCLD + GCV + PS will determine the required ratemaking adjustments if the property earns the IOU its average rate of return or more on an investment at that valuation level. Commensurately lower values, even down to OCLD (and in very rare instances, below it), may be used otherwise. The CPUC adheres to this tradition, and thus valuations and recoveries below that income-based level will cause the IOU to be denied a reasonable value for its property devoted to public service, and they will constitute at least a partially uncompensated taking.

event, for purposes of this analysis, the argument was resolved in the IOUs' favor by AB 1890, which allows them recovery of substantially all stranded costs, via a "competition transition charge" (CTC), from ratepayers of the IOU or of a municipal system that allows an IOU's former retail customers to bypass the IOU. On the other hand, AB 1890 also removes the stranded-costs element from the computation of the takings compensation by requiring that the lost IOU net revenues be reduced from what they previously would have been by the amount of the CTC. That is, there can be no double-counting of the stranded costs, and since the IOUs now recover them in rates, they cannot be counted in valuation for condemnation (and so we do not do so here).

The two factors above show the fallacy in arguments for income-based methods as a way to get to an OCLD valuation basis in takings: both the stranded costs and the subsidies paid from one area to another via area-cost-averaged rates are book costs that IOUs are reasonably allowed to recover[8] through sales to their ratepayers. Hence, both costs should be covered in a condemnation valuation, except where the CTC provides for recovery in rates even after the taking by the muni. Put another way, an income method does lead to book-value-based compensation for a distribution system taken from an IOU. However, that does not mean it equals the OCLD of the distribution system's assets considered in the abstract on a stand-alone basis -- because in utility regulatory treatment, the book value of the assets taken and other damage inflicted on the IOU and its remaining ratepayers, considered in the context of those assets' role in the IOU's overall system, is not limited to their stand-alone OCLD. Thus, the assumption that the assets in question are earning only the system-wide average rate of return in the income method (the way to get to OCLD via this method) is equivalent to circumventing the conclusions of law of the IOU's regulators that area-cost averaging and recovery of all book costs prudently and reasonably incurred by the IOU are fair, just, reasonable and required.

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[8] In saying this, we do not mean that all stranded costs -- that is, all uneconomic costs incurred by an IOU -- should be recoverable from its ratepayers under regulated ratemaking or from a condemnee in a taking. The portion of stranded costs to which we refer here as being compensable in a taking from an IOU is that portion which the IOU's regulators have found is fair, just, reasonable, equitable and economically efficient for it to recover from ratepayers.

However, when such errors are avoided, an income method is, most economists hold, a reasonable way to determine the economic value of assets in a taking -- usually the most reasonable single approach if market surveys are not possible. An income method reflects the basic notions of value, according to micro-economic theory and financial analysis, that determine a buyer's willingness to pay a given amount for an asset in a voluntary transaction, as well as a seller's required price. On the other hand, actual implementation of these methods is often much simpler than full implementation of the underlying theory -- so, real-world income analyses are not perfect indicators of value, nor the only ones.

c. RCLD

As discussed below, an RCLD estimate represents an attempt to measure the appreciated value of the assets due to development around them since they were installed (or, in cases of replacement by systems with new designs, etc., possibly a reduced value of them). Also, it sets an upper bound for income-based estimates. A valuation as the sum, RCLD + GCV + PS, is widely used in legal precedent. The basic replacement-cost RCLD idea is to estimate the cost and thus the value of the asset at current prices and designs, rather than based on the price levels and designs at the time the asset was built or bought. Differences in price levels for an asset over time are driven by two factors: inflation (or deflation: negative inflation) and technical progress in the design and production of the asset, and this method is an attempt to capture both effects. As noted above, because technical progress and design evolution are very slow in electric-utility distribution systems, reproduction costs may be a good surrogate for replacement costs here. The main problem associated with the simple RCLD estimate is the fact that it does not reflect the value of the asset taken in the context of the business use to which it is currently being put, nor the severance costs. This is addressed by adding the GCV and PS elements to the RCLD base.

The foregoing discussion of the concept and adaptations of the RCLD idea reveals its strengths and weaknesses. On one side, it reflects the idea that if building or procuring the original asset was economic in the sense that its initial value was at or just slightly above its cost (the typical

result in equilibrium operation of many enterprises), then a short-cut to reflecting the asset's current value is to merely reflect its price-level changes by replacing OCLD with RCLD. On the other hand, because utilities have an obligation to serve, they must often build infrastructure that is not economic in the sense of meeting this value-versus-cost test. Hence, some assets are not worth their cost at the outset, and their RCLD will be justified only when there has been significant area development following their installation. (Even development may not be enough, however, because it may also raise the RCLD in the area.) A weakness in the method, then, is that it assumes that the economic context in which the asset is now set is one that would justify replacement or reproduction. Even the refinement of adding GCV + PS to the RCLD is, like the RCLD itself, somewhat ersatz, especially in contrast to the direct and prospective treatment given these matters using income methods.

Ultimately, the RCLD idea has benefits of simplicity, directness, a very tangible aspect, and some intuitive appeal, especially to non-economists. For assets and business operations that can be relocated (not electric-utility distribution systems), this approach rests on the notion that compensation is required to a level that allows the current owner to start over today and be in essentially the same position it was before the taking. Another benefit is that RCLD reflects appreciation which income methods also capture in theory but often miss in practice. In sum for economists, RCLD + GCV + PS represents a simple proxy for the economic value of an asset, but it is often inferior to an income approach. The benefits of the RCLD approach are understandable to non-economists, though, and income methods are more opaque to them. Due to the theoretical problems of the RCLD methods and the implementation weaknesses of the income methods (as contrasted to what they promise in theory), it is not surprising that the legal tradition, to which we turn following a review of depreciation issues, generally accepts both and rests on the trier of fact weighting results of these two valuation methods appropriately in setting the final value.

d. Depreciation: Straight-line v. Economic (Sinking-fund)

In a valuation context, an allowance for depreciation represents the attempt to reflect the change in value over time of an asset. Although many people think of depreciation in terms of the

condition, operating characteristics or even output of the asset, it is usually more related to the fractions of the service life of the asset that have already passed (the accumulated depreciation allowance) and that remain (the net depreciated value). Notwithstanding this fact, to many non-economists, SL depreciation makes intuitive sense, because it allocates the nominal asset value evenly to all service periods.

Economists recognize that, in a market context, the value of an asset is determined by the remaining years of life in the asset, and that value today is not linearly proportional to the number of years. Economically rational people will value prospectively service during the next year more highly than service during the following year, and each successive year is valued less still, due to the greater uncertainty and inherently lower present value of service in increasingly remote time periods. Without going into its technical details, economic depreciation represents a present-economic-value approach to precisely implementing these notions, and it leads to a depreciation schedule that has low depreciation allowances over the early years of an asset's life, increasing with time. The longer the asset's life is, the greater is the difference between early- and late-year depreciation amounts. Finally, economic depreciation usually reflects the change in physical condition or practical serviceability of an asset better than does SL depreciation.

A problem for economic depreciation is that, even though modern computational technology has removed the barrier due to its somewhat complicated mathematics (once a small barrier), it is still not well understood by the public or even most business and public-policy decision-makers. SL depreciation, on the other hand, has wide currency, even though it is not economically truly sound. Thus, to the extent they use SL depreciation (and they do to some extent), practice and legal support diverge from economists' preference for economic depreciation, as the next sub-section shows.

2. Valuation: Legal Standards and Voluntary Transactions

Perhaps the easiest and clearest way to understand the legal standards for valuing assets in legal takings, and the standards' development, is to view the issue in terms of the interests of the

parties: condemnors (here, municipalization advocates and SF), who want low values; and condemnees (IOU advocates and PG&E), who want high values. While both parties are, one presumes, concerned with analytic rigor in valuations, they are very interested in the value of a method in terms of getting them either a high or low value. This approach is instructive because it shows that whether a method leads to a high or low value depends on economic trends over time; thus, as there are long-term changes in the trends, parties' positions on them tend to reverse.

The traditional battle, beginning in the early decades of this century (not long after electric utilities came into being), focused on a choice between OCLD and RCLD, because market survey (comparable sales) and debt/income methods were generally not applicable for the same reasons as today, and because income methods had not in the early years of that period been developed and later were considered by courts as speculative. During some early periods, real declines in costs and periods of deflation (especially during the Great Depression of the 1930s) made RCLD estimates yield lower values than OCLD. Hence, municipalities often favored RCLD, and IOUs supported OCLD (and in times of opposite trends it was vice-versa).[9] Since the 1940s, however, RCLD has generally led to higher values for utility distribution systems, and thus it has been favored by IOUs, and OCLD has been supported by municipalization advocates.

The California Railroad Commission (CRC, the fore-runner of the CPUC), heard a number of cases involving municipalization efforts of electric-utility service, beginning with creation of LADWP in 1916 and one in Redding in 1917, 1919 and 1921, followed by three unsuccessful efforts: San Francisco (1929); Fresno (1936); and Redwood City (1936). In the final major case, involving the creation of SMUD in 1942 (*In re Sacramento Municipal Utility District* (1942), 44 Cal.R.C. 467; 48 P.U.R. 321), the Commission generally embraced the RCLD + GCV + PS formula as the

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[9] Also, at any one time, a party could find itself on both sides of the issue, depending on the purpose or use of a given valuation. Thus, when utilities wanted RCLD (high) valuations of their property in condemnation, they argued for other (low) bases for property tax purposes related to the same assets.

standard.[10] This has a certain regulatory logic when the choices are limited to RCLD and OCLD (per se) variants due to lack of applied income methods (which by this time had begun to be developed in economic theory, but still had little legal currency). The logic is based on the assumption that the areas most likely to municipalize are the low-cost areas which the utility regulator, through area-cost averaging, requires to pay rates higher than those that would be based solely on local OCLD asset values. If these areas exit the IOU system through municipalization at acquisition costs below the IOU's system-average investment levels, then costs will rise for the remaining customers. Thus, requiring RCLD + GCV + PS valuation is a way to recover for those captive customers at least a portion of the contribution that would otherwise have been made by the customers departed, if they had stayed with the IOU.[11] This standard stood for three decades, unchanged, until the economic (income capitalization) methods began to be applied more widely in valuation analysis. In the meantime, the locus of major decisions on these matters shifted from the CRC/CPUC to the civil courts, but the body of CRC/CPUC precedent remains applicable in California utility condemnation.

In 1976, in a landmark case, the California civil courts shifted somewhat away from exclusive reliance on the RCLD + GCV + PS orthodoxy to allowance of various methods, especially RCLD (without a particular depreciation approach preferred) and income methods. (*South Bay Irrigation District v. California American Water Company* (1976), 61 Cal.App.3d 944.) Because municipalization cases have been rare in recent years, there has been almost no new legal precedent since then. Roughly summarized, the legal valuation tradition today is that RCLD + GCV + PS will determine the required ratemaking adjustments if the property earns the IOU its average rate of return

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[10] The valuations in that case generally relied on sinking-fund depreciation, because the CRC at that time still required it for ratemaking purposes and the CRC wanted the transaction to be consistent with its ratemaking accounting. Thus, much should not be made of this aspect of the decision, which was not one of the main points of contention. Further on depreciation, see the final paragraph of this section, which addresses case law relevant to it.

[11] We do not mean to imply a blanket endorsement of RCLD, area-cost averaging or cross-subsidies here -- just to point out that, to the extent the regulators supported at least the latter two, then RCLD methods are consistent with that position. The support of the regulators for large utility service areas reflected the fact that there were unexhausted economies of scale in the electric-utility business at that time that would be lost by balkanization into municipal utilities; economic and technical developments since then have also diminished or removed this as a reason to prefer such integration. Regulators' opposition to book value, per se, also reflected a growing awareness that they do not reflect economic value, as discussed in the previous subsection.

or more on an investment at that valuation level -- and commensurately lower values, based on income analyses and even down to OCLD, may be used otherwise. In short, the valuation question in municipal condemnation has moved a great distance toward the economists' view that income analyses are preferred, but has maintained an anchor in the RCLD + GCV + PS tradition. The question now becomes one of whether the system being taken is the whole system; or, if a part of a system, is a relatively profitable part or an unprofitable one. Of course, as various cases show, if market data are available (as they are not for electric utility systems), then survey or market methods may be presented; in fact, if they are extensive and reliable enough, they will tend to eclipse the replacement-cost-formula and income methods. Another aspect on which some water utility cases have focused and which has inherent relevance for any business is the condition of the assets. This issue may arise for CCSF in determining the depreciation in the RCLD methods, and as noted above, it will favor economic depreciation.

A number of voluntary transactions have also occurred in California, and cases have been tried before both judges and juries involving valuation of electric-utility assets taken by municipalities, as shown in the nine-page table in workpapers WP-2.A. These sales and cases have reflected this standard, with most of them resulting in RCLD + GCV + PS determinations, where the valuation basis is known. Often, it cannot be known because juries do not decide methodological issues, but only the value; at other times, the parties have agreed to make a transaction (with or without litigation) and do not want to state a particular valuation basis their agreement, even where it was clear to both sides. A number of cases have also been heard by the CPUC for the ratemaking consequences of sales, either in condemnation or on a voluntary basis by IOUs of electric-utility property to municipals, and as the table shows, they have followed the same tradition.[12]

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[12] In civil cases (and to a lesser extent in regulatory cases, where the presiding administrative law judge or commissioner can to a great extent affirmatively determine what evidence parties offer), precedent in this matter is complicated by the roles and interests of the parties. Thus, litigants are likely to protect themselves from a trier-of-fact's preferences between the methods by presenting evidence using each method if possible. On the other hand, judges and commissions, if they hew to the legal principle of deciding only as much as needed to settle the contested matter before them, will generally not enunciate an overall theory on how they view the matter; instead, they will review all the evidence and then tend to come to a conclusion that reflects the weight they assign it (a subjective and often not understandable matter). Hence, the system has a bias toward continued presentation by parties of a wide spectrum of evidence -- which leads often to different results, depending on who is the trier of fact -- i.e., whether it is a bench or jury trial, and on the judge's views.

The final aspects of this matter, then, because RCLD + GCV + PS is a reference point (albeit not exclusively) are the depreciation method to be used in RCLD determination and the methods for determining GCV and PS. The case standard for depreciation dates from 1922 (*Pacific Gas & Electric Company v. Devlin* (1922) 188 Cal. 33.), which concludes essentially that the depreciation method is a factual matter to be determined by the particulars of a given case. There appears to be little definitive other guidance, and results from contested cases, as well as from voluntary transactions, are not uniform. In general, SL depreciation seems to be favored, but where the costs to serve an area are low enough, economic depreciation (yielding a higher compensation) may be used -- just as values below RCLD + GCV + PS, down to even OCLD, are used for areas with high costs of service. In any event, an RCLD estimate using economic depreciation is admissible evidence, and since it benefits the condemnee (here, PG&E), one can be sure that it will get into the record, while the SL version may not get into the record if neither party wants to sponsor it. GCV is nearly universally computed as a percentage of the RCLD, and in the PG&E cases it has nearly uniformly been 15% of RCLD, based on some early studies of direct estimates by that company that showed that 15% was a typical or average figure. PS is simply an engineering estimate of direct costs, and is usually relatively small.

To sum up, the legal principles for electric utility distribution systems in California appear to be these:

- Book value, per se, might not be admissible as evidence of value; however, it is relied on somewhat in connection with regulatory matters, mainly where an income valuation shows a very low estimate.
- Reproduction- (or replacement-) cost formulas and income-based valuations are admissible and preferred, especially in the absence of direct market data; but if real market data are available, they may assume great importance if broad and reliable enough; otherwise, there is no particular preference accorded to the results of an admissible method (i.e., as between income and replacement-cost methods).
- The depreciation method to be used is a matter of fact to be determined by the trier of fact, and thus a very wide range of evidence is allowed on this matter, with no particular

hierarchical rules for it. The economic (sinking-fund) depreciation is almost certain to be put in the record by the condemnee.

3. Upshot: Base, High- and Low- Cost Valuation Cases

Based on the legal precedents and the role that economic analysis can or should play in influencing them, we conclude that a reasonable base case for valuing the SF electric-utility distribution system is RCLD(SL) + GCV + PS (i.e., the replacement-cost formula, with SL depreciation). We reach this conclusion partly because (as our analyses show) SF is a low-distribution-cost area that makes substantial contribution to the rest of the system in area-cost-average distribution pricing, and also because this value is a lower-to-intermediate value among the admissible figures (if PG&E were to succeed in introducing a higher RCLD(Economic) value than that which we estimated, as noted above). The replacement-cost formula was the standard used in the most recent successful contested electric municipalizations in California. In the same view, a high-cost valuation case is our RCLD(Economic) + GCV + PS estimate (the replacement-cost formula, using economic depreciation). Because the income-capitalization method yields the lowest value of the certainly admissible methods, it is our low-cost valuation case.

OCLD provides an outer limit of results from a court adopting policy arguments leading to a change in precedent. The possibility of high-cost boundary values from updated versions of estimates PG&E developed in connection with previous studies for the RCLD(Economic) + GCV + PS standard points out a great uncertainty in replacement-cost estimates made at the preliminary feasibility stage -- as we have done by relying on mainly on utility books and records (which was the only way possible in the time and cost constraints of this study), without doing a detailed in-the-field inventory and inspection of condition, review of work orders, etc. The problem is that this desk-study method often leaves a great range of uncertainty in the results that can be narrowed only by the inventory-based field study. To the extent that the wide range of uncertainty, coupled with the magnitude of the valuation dominates the decision -- which our results in chapter 4 show may not be the case here -- then a premium rests upon getting better replacement-cost estimates to predict a

valuation outcome with more confidence.

Before documenting our quantification of each of these estimates in the next two sections, it is important to clarify what the three values represent and what they do not. Primarily, they are an assessment of the likely outcomes of a condemnation valuation, not a normative statement of the economic merit of each method. Were we to choose on the basis of economic and policy merit, then the base case would be an intermediate figure below RCLD(SL) + GCV + PS (i.e., closer to the income capitalization approach), because in our view it uses the soundest method.

The likely valuation, however, rests both on our evaluation as economists of the methods and on the applicable evidentiary rules. In fact, our evaluation is that the legal precedent is generally economically sound in barring OCLD estimates, admitting income and RCLD results, and having the trier of fact weigh the estimates based on these two methods to determine the valuation. Juries and judges may, through no fault of their own, err (high or low) in understanding and weighing the evidence, but the method is sound, and we believe on average it leads to sound results. Thus, for example, to the extent that a valuation exceeds the income-based estimate, it may be reasonable as reflecting some appreciation of the asset's value since it was built or installed. In this context, a muni condemnor gets full value for an asset priced above an IOU's average rate base on which its rates are set, because it is buying a property at full value and may reap that full value for its ratepayer/owners.

CCSF can assume that the income capitalization value and all RCLD method results discussed here will be admissible. PG&E will, of course, present the highest one it can support. If the OCLD estimate is not admitted, then a range defined by the PG&E figure and income capitalization would be centered roughly around our (much lower than PG&E's) estimate of RCLD(Economic) + GCV + PS. If the book value were allowed in, then the range centers roughly about the RCLD(SL) + GCV + PS. Of course, either party always has the option of presenting supplemental showings based on the methods preferred by the other side -- something often done in the context that, even using the other side's preferred method, a correct implementation does not favor its number, but instead a different value. The problem with such a showing is that it tends to undermine the position of the

party making it. Clearly, such a chess match can be gamed at length, subject to the law of diminishing returns. But just as clearly, the problems of getting the book value into evidence favor the range defined by our two RCLD estimates for the likely outcome. Even though the higher RCLD value is more sound in RCLD theory, we have chosen the lower of these two estimates based on our subjective weighting of the income-capitalization and RCLD(Economic) + GCV + PS results and on a possibility that the policy argument may bring in the OCLD estimate. Our own subjective view is that the true value is between our income-capitalization value and the RCLD(SL) + GCV + PS value, and thus our use of the latter figure is somewhat conservative -- meaning that, if this view prevails and if its results favor municipalization, they already incorporate some margin for error (i.e., a high valuation) in the overall assessment.

A final note on the valuation issues here: in its recent publications, the American Public Power Association (APPA) has stated some views similar to those we adopt here on valuation in condemnation of electric-utility distribution systems. In particular, in "The Value of a Public Power Distribution System: Increasing, *Not* Decreasing", (APPA, September 1996) David W. Penn, APPA's Deputy Executive Director, discusses at length reasons that net book value (or OCLD) is not a correct valuation for an electric-utility distribution system in the emerging utility market. He states that the true value is much higher, as shown in the quotes below (with their footnotes omitted):

> An investor-owned utility (IOU) in the mid-Atlantic region puts on a full-court press to buy out the medium-sized municipal electric distribution utility. It makes an offer above the book value of the assets. It increases the offer during negotiations. The offers are way above what the same IOU offered to buy out the same public power utility three or four years ago -- a time before the threat of retail wheeling was being bandied about.
> (...)
> As for the facts, in general the value of publicly owned distribution systems is not decreasing. To the contrary, it is holding steady or increasing. This is the worst time to sell an income-producing asset, to kill the goose that lays the golden eggs.
> Lets's look more carefully at the restructuring and competition changes taking place in the electricity industry and at what their true impact is likely to be on the value to a community of owning its own distribution utility in the future.
> (...)

> The logic of selling a public power distribution system at this time cuts directly against the facts. An electric distribution system has never been more valuable.
> (...)
> Pacific Gas and Electric Vice President Jim Macias, commenting on his giant company's business strategy of moving away from generation, said: "The wires and distribution business will provide a 'stable platform' insulating utilities from what will be more volatile earnings."
> (...)
> Except in rare circumstances and in only certain places in the country, an existing distribution network will not be duplicated and hence not lose value.
> (...)
> If you will, the wires or distribution system is a cash register.
> (...)
> Finally, an asset provides its owner with a future stream of income, or profits from the IOU perspective. The testimony cited above from numerous IOU representatives as to the value of this future stream of revenues could not be more eloquent -- an annuity, a stable platform, a source of steady profits for the acquiring company.
> The future stream of profits will go to the asset owner. By holding on to its wires -- to its existing asset -- a community will continue to be the recipient of this future stream of benefits.
> (...)
> Public power communities need to recognize the true worth of their network of poles and wires and not be deceived into thinking that the value of their distribution utility will diminish in the future competitive world of that it will be too complicated for them to operate and maintain.
> Those who would acquire your municipal distribution utility want your valuable asset -- the wires -- and they want what your distribution wires provide, namely, your connection with the customers in your community. If a public power distribution system and serving its load is about to become so worthless, why would an IOU offer to buy such an asset? The words and actions of industry leaders make it clear just the opposite is true. The value of a community owning its own distribution electric utility is, if anything, increasing in the face of the new competitive world.

The main reasons cited in APPA's document for the value of a distribution system apply to IOUs (albeit not some of the other minor reasons it argues), as well as to munis. The APPA cites to statements by "industry leaders", including a PG&E executive, show that they also recognize this point. Hence, in either side's hands, a distribution system's value exceeds book value and appears to be increasing as a result of industry restructuring.

B. *Description of the CCSF Electricity Distribution System*

1. *Introduction*

This section of the report presents a summary description of the SF distribution system and identifies the assets that would be taken from PG&E in order to establish a municipal electric utility in San Francisco.

2. *Typical Electricity Distribution Systems*

Figure 2-2, on the next page, contains a diagram which summarizes the function of an electric utility distribution system. Electric energy is carried along transmission lines from the point of generation to customer load centers at (high) voltage levels between 110 kv and 765 kv. Nearly all customers require much lower voltages to power their lights, motors and appliances. Therefore, the bulk transmission level voltage is reduced by a bank of step-down transformers, located within a substation, for delivery over primary distribution lines extending throughout the distribution area. For users needing even lower voltages, the voltage is reduced once again by a distribution transformer or line transformer. At this point, the voltage changes from primary to secondary distribution voltage. Voltages in the distribution system range from 60,000 to 120 volts and are linked directly to the customer's meter via the service line.

In addition to substations and transformers for reducing voltage, distribution systems include regulating and protective equipment to help ensure steady and safe operation of electrical equipment. Circuit breakers are installed at the substation in order to disconnect major feeder lines from the power system in the event of an overload that could cause damage to customer equipment. Most distribution lines consist of insulated cables, which may be carried aboveground or underground. Homeowners (residential customers) are generally suppled with 120-volt current for lights and most appliances, and also with 240-volt current for electric ranges, heat pumps, and water heaters.

Figure 2-2

Flow of Electricity - Generation to End User

Generating Plant ->---*Switchyard Step-Up*--->---Bulk Transmission (110 kv-765 kv)--------->

Step-Down Substation-- >-----High Voltage 23kv-138kv---for Bus, Street Rail & Industry -->

Step-Down Substation-- >----Medium Voltage 2kv-60kv ----for Commercial & Industrial--->

Secondary or Line Transformer--------- > Low Voltage 120v-480v ----> for Residential.

The analysis of the cost of acquiring PG&E's SF distribution system begins roughly at the point where the bulk power transmission lines enter the substation.

3. Specific Attributes of the CCSF Distribution System

a. Physical Layout and Area Reliability Issues

SF has a concentrated metropolitan electricity load that is supplied from a single transmission source and local generation. Unlike most other major cities, which have multiple transmission sources of electricity supply, the local SF load cannot be reliably supplied without local generation under current conditions. PG&E has developed operating criteria to meet San Francisco's unique reliability requirements, the "San Francisco Operating Criteria" or SFOC. According to PG&E, the purpose of the SFOC is to utilize local generation as necessary to provide electric service reliability to San Francisco that is equivalent to the service reliability PG&E provides to other metropolitan areas. SF receives the majority of its electricity supply from a single transmission corridor along the

peninsula past the San Francisco airport to the Martin Substation. The single transmission corridor consists of one 230 kv and five 115 kv transmission lines. Local generation consists of two aged and two relatively efficient gas/oil fired steam generating units and four quick-start combustion turbines.

Since the single transmission corridor is not capable of supplying 100% of the San Francisco area load,[13] local generation from the Hunters Point and Potrero generating stations is used to supply a part of the local load and to prevent equipment overload, cascading outages, voltage collapse, and a total area blackout following a single contingency transmission corridor outage or a system disturbance outside the San Francisco area.

A SF municipal electric utility will have to meet this or a similar reliability criteria. This fact would have had an important impact the valuation study (negative to municipalization), given the large costs of owning, and (especially) operating and maintaining the SF generating stations, but for the advent of the restructuring of the electric utility industry in California.[14] Before the CPUC's restructuring initiative in 1995 and the passage of Assembly Bill 1890 in 1996, a San Francisco municipalized electric utility would have had to purchase, own and operate the SF generating stations or pay PG&E for the costs of ownership and operation. Another land-based interconnection on the Peninsula would be of questionable reliability value, and it is uncertain whether and when one could be built in view of current environmental and related regulations. However, it is our conclusion, after analyzing the provisions of AB 1890, that a SF municipal electric utility will not be required to purchase the existing Hunters Point and Potrero generating stations from PG&E. We have therefore excluded these generating assets from our analysis of the cost of acquiring PG&E's distribution system within the SF. On the other hand, as discussed in chapter 3, creation of a new electric utility service territory in SF may trigger the allocation of the reliability costs associated with the operation of Hunters Point and Potrero generating units directly to SF electric ratepayers.

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[13] The San Francisco Area Load is San Francisco's load and a small fraction of the Peninsula electricity load.

[14] WP-2 contains details on the capital and operating costs of the Hunters Point and Potrero generating stations.

b. Customers and Customer Loads

As of 1995, SF had approximately 334,000 retail electric customers. Since 1981, the total number of retail electric customers has increased only by 27,000 or 8.8%. Total kWh sales by PG&E within SF were 4,503,438 MWh in 1995, and revenue to PG&E from electricity sales within SF was $483-million dollars. The average revenue per kWh was $0.1078. SF accounts for 7% of PG&E total annual electric sales and electric revenues. Total annual kWh sales have increased by 840,000 MWh, or 23%, between 1981 and 1995. A breakdown of kWh sales by customer class for the recorded year 1995 is as shown in Table 2-1 below. Note: Besides the volumes shown there, the SF distribution system also distributes Hetch Hetchy-generated electricity for municipal use by The City and airport.

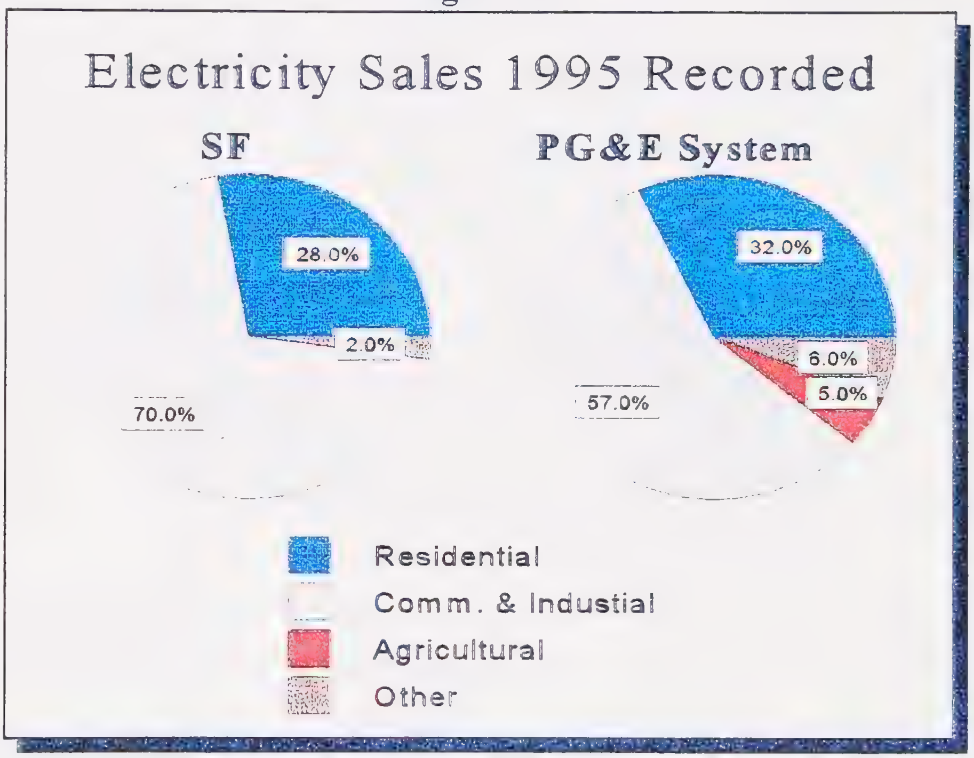
Table 2-1
Sales of Electricity by PG&E in SF
*1995 Recorded **

	MWH Sales	%
Residential:		
Individual Metered	1,139,507	
Master Metered	128,785	
Total Residential	1,268,293	28%
Light & Power (Commercial & Industrial):		
Non-Demand Metered	520,250	
Demand Metered Under 1000 kW	1,316,377	
Total Small Light & Power	1,836,626	41%
Demand Metered 1000 kW & up	1,309,189	29%
Total Light & Power	3,145,815	70%
Other:		
Agricultural	142	
Street Lighting	1,973	
Public Authority	9,232	
Railway-BART	50,063	
Interdepartmental	27,920	
Total Other	89,330	2%
Total Sales	4,503,438	100%

* **Source**: FERC Form 1 and PG&E Customer Accounting Department. Recorded data and not weather normalized.

Figure 2-3, below, presents a comparison of SF with the PG&E system for the recorded year 1995. The PG&E data were taken from the 1995 Annual Report to the CPUC. The electric sales profile for the PG&E system, as compared to SF, has less commercial and industrial sales and more residential sales. As a general rule, it is less costly to serve higher load-factor customers, and commercial and industrial load factors are generally higher than those of residential customers.

Figure 2-3



The historic peak demand[15] of SF, excluding the SF airport, grew by a modest 7.5% from 810 MW in 1984 to 870 MW by 1995,[16] as compared to the 25% growth in the PG&E system peak

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[15] Peak demand is the maximum momentary electric usage (or power demand), by customers, within a geographic area of the system, or for the entire system, measured in KW, during a specified period.

[16] Data were taken from PG&E's rate-design workpapers filed in its 1996 general rate case before CPUC

demand during this same period.[17] Because electric utilities must size their distribution facilities to meet the local customers' aggregated peak demand, the growth in peak demand directly affects the rate of investment in distribution assets. PG&E projects that the SF peak demand will increase by only 30 MW by the year 2004. Our review of PG&E data for SF indicates that the SF peak will occur between June and October on the hottest day of the summer in Northern California and fairly close to the time of the PG&E system peak.

SF contains a more concentrated electricity load and distribution area and has relatively lower customer and peak demand growth than the remainder of the PG&E system. In addition, a greater proportion of electricity sales in SF are made to commercial and industrial customers which, on average, have lower distribution costs per kWh sold than residential customers. This indicates that SF is a relatively low-cost electric *distribution* service area when compared to the PG&E system as a whole. There are other cost factors which may offset the relatively low distribution costs in SF. The unique reliability requirements of SF and the need to operate and maintain the SF generating stations are one example, and high underground retrofit costs the SF is another.

c. Description of PG&E's SF Electric Distribution Assets

In order to establish a municipal electric utility, CCSF will have to acquire from PG&E certain transmission and distribution assets consisting of: 1) an underground high-voltage 230 kv cable system that serves only SF; 2) the distribution system which distributes electricity within SF and represents 90% of the acquisition cost; and 3) the Martin Substation, which is located just across the county border in San Mateo County. As stated above, our opinion is that a municipal electric utility will not have acquire the Hunters Point and Potrero generating stations which are located in San Francisco, and thus no capital costs for these assets are included in the valuation.

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[17] Source: 1984 FERC Form 1 and 1995 FERC Form 1.

The SF distribution system can be further broken down into two distinct distribution systems: the Network Area and the Radial Load Area. The Network Area covers 1.2 square miles of the downtown core area. Retail electric customers in the Network Area are predominantly commercial high-rise office buildings, large retail centers and high rise hotels. It contains about 22,300 retail customers who consume more than half of the electricity distributed in SF.

The Radial Load Area covers the remainder of SF and contains over 312,000 electricity customers. This area is a mix of residential, commercial and industrial loads, and electricity is distributed via underground and overhead conductors.

C. Valuation of the SF Distribution System

1. Analytical Framework

This section presents our implementation of the analyses and modeling required in order to establish a range of condemnation compensation values for that portion of the PG&E distribution system within SF. It should be noted at the outset that our implementation of the valuation methods in this study is necessarily an imperfect approach. Simply stated, PG&E does not maintain separate accounting records that contain an inventory -- i.e., the type, number of units and cost for each component of the SF distribution system. In other words, there is no current, publicly available information that would reveal PG&E's investment in transmission and distribution plant and equipment within SF. PG&E is not required to, nor does it, maintain a separate set of plant accounting records for SF. For this reason, and because of the time and cost limits placed on the study, we cannot start the valuation process with a detailed, inventory-based, original-cost estimate of PG&E's SF transmission and distribution assets.

ETAG has prepared its estimate of the original cost and replacement value of PG&E's SF distribution system, and associated assets, based on the available data. Two basic analytical methods

were employed: an accounting-based method and engineering-based method. The accounting-based method was used to estimate the original cost and the related accumulated book depreciation to produce a net book value, or NBV, estimate of the SF distribution system. The engineering method was used to establish the reproduction cost or RC of the SF distribution system. Standard accounting methods were employed in calculating both the straight-line and sinking fund depreciation, which were combined with the reproduction-cost estimate to produce reproduction cost new, less depreciation, or RCNLD.

While the most significant constraint on the analysis for both the accounting- and engineering-based methods is the lack of an accurate and detailed inventory of all or a majority of PG&E distribution assets within SF, the secondary constraint on the analysis is that there is no direct way to accurately "vintage" or establish the dates when distribution equipment was placed in service. This point is of significant importance because both the net book value and RCLD values depend on the age of the assets to be acquired -- i.e., the amount of deprecation to deduct from the original cost values.

Nearly all major electric utilities maintain their accounting records for distribution assets on a system-wide basis without regard to city, county, or even state boundaries (the latter if the utility serves areas in more than one state), because rates are usually made on a system-wide basis. This is the case for PG&E.

In addition, given the massive numbers of individual distribution plant items and their relatively small cost per item, the only cost-effective manner to maintain the books of account for a significant portion of the distribution plant is to use system-wide "mass accounting" for the various categories of distribution plant. Thus, for example, we can determine the original cost of all "Poles, Towers and Fixtures" installed by PG&E within its service territory from publicly available information. We can also determine the amount of book depreciation accumulated for all "Poles, Towers and Fixtures" in the PG&E system. However, there is no existing set of publicly available

accounting records that would identify the "Poles, Towers and Fixtures" installed in the SF and date when they were installed in SF.

Determining an accurate historic cost and replacement value for PG&E's distribution and related facilities that currently serve SF will require a time-consuming and costly inventory of all PG&E transmission and distribution assets within SF. In addition, another time-consuming effort to relate that inventory to installation dates through indirect sources such as work orders, job records and maps (were they exist) will also be required. This level of effort should be undertaken if the CCSF decides to conduct a more extensive feasibility study on the merits of municipalization or to proceed with it.

For this study, ETAG has acquired and analyzed all relevant and publicly available data in preparing its estimate of original cost, accumulated book depreciation and net book value, and its replacement-cost estimates. The publicly available information includes PG&E's annual fillings of information with FERC and the CPUC for the last 16 years, and data submitted by PG&E in its 1993 and 1996 rate case fillings before the CPUC. ETAG has also acquired a PG&E operating diagram for the SF distribution area (FERC Form 715). We have also reviewed a prior study of this issue that was performed in 1988.

2. Estimating Net Book Value

PG&E, in its annual reports to the CPUC and FERC, provides system-wide, total-cost data for its distribution assets. This data is reported by plant account as specified in the Uniform System of Accounts and as prescribed by the FERC and adopted by the CPUC. For distribution accounts, PG&E lists the original cost, the average service and the average remaining service life of the distribution assets. Therefore, its is possible to track, over time, annual gross plant additions, changes in the embedded average service life and average net remaining life for the nine major categories of distribution plant, but only on a system-wide basis.

Because we have data on the total number of retail electric customers in the PG&E system, we can calculate average system-wide distribution gross plant, book depreciation and net book value on a per-customer basis. The most facile approach would be to simply multiply the system average per-customer values for distribution plant as of 1995 by the number of electric customers within SF to arrive at the net book value for the SF distribution system. However, we believe that such a simple approach would substantially overstate the net book value of PG&E's investment in distribution assets in SF. The basis for our concern in using average system-wide per customer data is based on the following facts[12]:

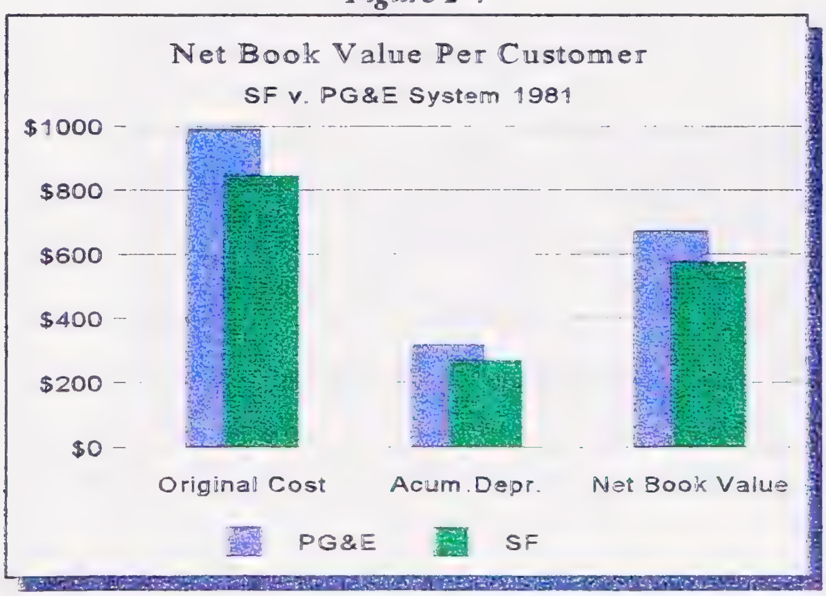
- Total gross and net book value of the PG&E distribution system has increased by nearly 300% between 1981 and 1995.
- System-wide, the total number of PG&E retail customers has grown by 25% from 1981 through 1995, while retail customer growth in SF was only 8.8%.
- The PG&E system-wide average net book value of distribution plant per customer has increased by 75% between 1981 and 1995.

Based on our experience in the electric utility industry, we concluded that this rapid growth in PG&E's system-wide distribution plant cost is closely related to new customer additions. During the 1980s, SF's electric customer growth rate was only 0.6% compounded annually, compared to the PG&E system average of compound annual growth rate of 1.69%. Adding new customers increases the average cost of distribution plant because of the need to install new plant and equipment. Therefore, use of average system-wide per-customer data to estimate the net book value of PG&E's distribution system within SF would in our opinion, prejudice the outcome of the analysis in by overstating the value of the SF distribution system.

[12] The source of the data on PG&E's distribution investments and customer growth was taken from FERC Form 1 filings from 1981 through 1995.

We believe that the base period for the analysis of NBV should be 1981, for which data are shown in Figure 2-4. This starting point was chosen for several reasons. First, relevant data is available from 1981 forward from the CPUC and FERC. Prior to 1981, it is extremely difficult, if not impossible, to retrieve such data. Second, the massive growth in distribution plant investments, which exceeds customer growth by a factor of ten times, began in the late 1970s. Third, PG&E prepared an estimate of original cost and average age for the key components of its SF distribution system as of year-end 1981. We compared this year-end 1981 estimate of the to the system-average cost data in the 1981 FERC Form 1 (FERC 1) and determined that the average invested cost of distribution plant per customer for the PG&E system was $990, versus $845 per customer, or about 85% of the system average, in SF. We also compared net plant (OCLD) on a system-wide basis with our calculation of net plant for SF as of year-end 1981. The SF net plant was also approximately 85% of the system average. We determined that the 1981 estimate of the original cost of the SF distribution system is a reasonable starting point for our analysis of NBV. The results of our analysis of the original cost, accumulated depreciation and net book value for 1981 for SF distribution and the PG&E system, on a per customer basis, is presented in Figure 2-4.

Figure 2-4



3. ETAG's Estimate of the Year-end 2001 CCSF Original Cost and Net Book Value

a. Method

As stated above, ETAG estimates that the most reasonable date to assume for a transfer of PG&E transmission and distribution assets to a SF municipal electric utility would be at year-end 2001 and that municipal electric operation would start at the beginning of 2002.[13] Thus, we must estimate the NBV of PG&E's SF distribution and related assets as of year-end 2001.

The starting points for our analysis are the 1981 SF distribution, etc. original-cost, accumulated-depreciation and net-book-value balances. At 31 December 1981 the estimated NBV of the SF distribution, etc. assets was approximately $194-million. The objective here is to account for changes in original cost, accumulated book depreciation and the resulting net book value over the period 1982 through 2001. There are three key factors that determine changes in net book value, over time, in PG&E's SF distribution system:

1. customer growth;
2. replacement of existing plant and equipment; and
3. accumulated depreciation.

We prepared detailed forecasts of expected changes in plant and equipment balances for 1981-2001. The net result is an estimate of the NBV of the SF distribution system as of year-end 2001.

b. Results of Analysis - NBV Estimate Year-end 2001

As of year-end 2001, we estimate the NBV investment by PG&E in the distribution system that serves SF will total approximately $315-million. Figure 2-5 on the next page contains our

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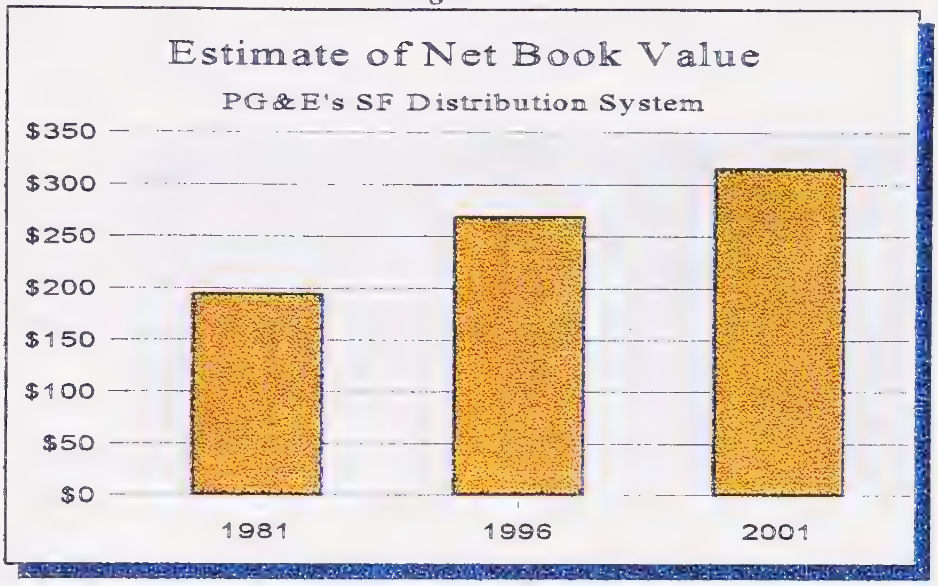
[13] See chapter 5 for explanation of the 2002 start date.

estimate of Net Book Value for the years 1981, 1996 and 2001 (WP-2.C). We carry this value forward to the overall analysis of the costs and benefits of municipalization in chapter 4.

Figure 2-5



4. ETAG's Estimate of RCLD

a. Method

The second method employed in estimating a value for the SF distribution system was to calculate the replacement cost of the distribution system as if it were reconstructed or reproduced today using today's labor, construction and equipment costs. This estimate is based on an engineering evaluation. The engineering evaluation produced an estimate of the physical plant and equipment required to transmit and distribute electricity to the 334,000 electricity customers in SF.

The starting point for the engineering estimate of reproduction cost is data we acquired on the physical attributes of the SF distribution system, customer data and electricity load data for SF. The detailed SF system diagram (FERC Form 715) and the Network and Radial Load Area maps and diagrams are taken from in work papers filed by PG&E in its 1996 CPUC general rate case

The engineering estimate was broken down into the following three distinct steps based on the availability of data and the quality and detail of that data:

1. Preparation of direct estimates of replacement cost for individual transmission-level, sub-transmission-level and unit substations, based on available system diagrams and equipment descriptions.
2. Preparation of direct estimates of replacement cost for various categories of distribution plant based on current equipment prices and unit labor rates.
3. In cases where there is no detailed design data or other information that could be used to create a direct engineering estimate of replacement cost, the estimate was based PG&E's original cost escalated to year-end 1996.

The estimate of replacement cost for substations was based on specific data for each transmission- and sub-transmission-level substation. This data includes the character and capacity, in MVA, of each the seven transmission-level substations and nine sub-transmission-level substations within SF. Estimates of the number and cost of sub-feeders were based on details in the PG&E operating diagram (FERC 715) and judgements as to what equipment is required. Design data was not available for the unit 17 unit substations. Therefore, estimates of the size and replacement cost of the 17 unit substations were based on known load densities for the Network Area and Radial Load Area and engineering judgement as to the type of equipment required for that distribution function.

The second step of the analysis involves preparing direct estimates of the plant and equipment required to distribute electricity from the substations to the 334,000 retail electric customers in SF.

Step three involves estimating reproduction cost, based on PG&E's original cost of installing equipment and escalating this value to year-end 1996. This indirect estimating technique was used in a limited number of circumstances where data, such as design and equipment specifications, were not available. This indirect estimating technique was used in the case of the underground 230-kv line that supplies bulk power to SF, and for the cost category of Structures and Improvements that primarily includes the buildings that house distribution-related equipment.

b. *Results of Analysis - Reproduction Cost*

The total estimated reproduction cost new, as of year-end 1996, is estimated to be $867-million. This estimate becomes the starting point for estimating the reproduction cost new less depreciation or RCLD (WP-2.C).

c. *Calculation of RCLD*

Clearly, the majority of distribution plant and equipment within SF is not new equipment. Therefore, an estimate of the depreciated reproduction cost is required if this value is to be used as the basis for determining a transfer price for the SF distribution system. In simple terms, depreciated reproduction cost means the current cost to reproduce or replace the plant and equipment new, less an allowance for the length of time it has been in service. As noted above, we do not have specific data on the vintage or age of SF distribution assets. Therefore, an estimate of the current age of each category of plant is required in order to complete the estimate.

The average age of any one asset category within the SF distribution system changes from year to year due to factors such as rates at which replacements are made to existing plant and equipment and the rate at which new customers are added to the system. We estimated an average for each category of plant and equipment based on the 1981 average age and assuming that replacements would occur at the approximate average rate of depreciation for each category of plant and equipment. The estimated age was adjusted for customer growth. The result is the estimated average age of plant and equipment for the SF distribution system as of year-end 1996. This estimate of average age is used along with average service lives to calculate the percent depreciation in the RCLD calculation.

The final key factor in estimating the value of the SF distribution system, using the RCLD method, is to employ a specific method of depreciation. As discussed elsewhere in this report,

differing methods of depreciation have been accepted by various courts in condemnation proceedings (see section 2.A). The seller of property would argue in favor of a depreciation method that maximizes the selling price and, conversely, the buyer would argue for a method which minimizes the price. Straight-line (SL) depreciation is used in our base-case RCLD estimate. However, we cannot rule out the possibility that some form of economic depreciation, most likely the sinking-fund (SF) method, would be employed in determining RCLD.

The straight-line method of depreciation amortizes the asset's value in nominally equal annual installments over its service life. As an example, an asset with a service life of ten years that is five years old would be 50% depreciated under the straight line method. The same asset with the same service life and age would only be 38.5% depreciated under the sinking-fund method. The disparity between straight line and sinking fund depreciation grows dramatically as the service life of the asset increases. A significant portion of the SF distribution system's assets have service lives that exceed 30 years, and some have services lives of 50 years or longer.

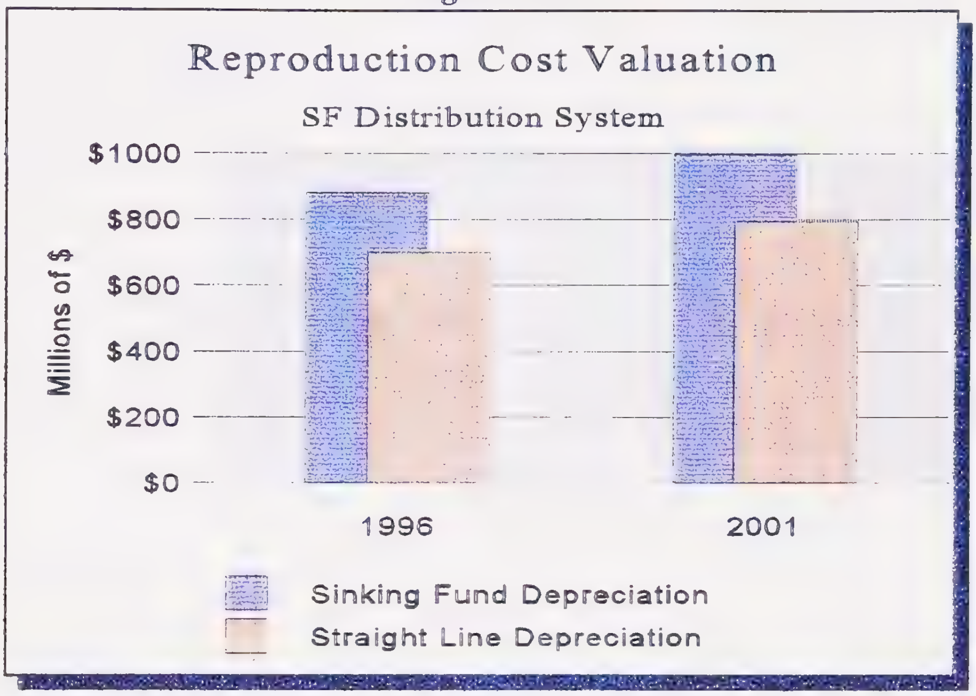
d. Results of Analysis - RCLD

As shown in Figure 2-6 on the next page, we estimate that value of the PG&E transmission and distribution system, using the reproduction-cost method and straight-line depreciation is $606-million at year-end 1996 before considering the going-concern-value (GCV) adder that is typically added to the RCLD value. As discussed in section 2.A above, the record indicates that a GCV adder of 15% is the norm. In addition to the GCV, we have included a rough estimate of $5-million for physical severance costs. Severance costs are the cost of installing metering and other equipment such as protective equipment to create two separate entities. Therefore, the total RCLD using straight-line depreciation and including GCV and physical severance $702-million as of year-end 1996. This value was escalated at 2.5% for five years to produce a year-end 2001 value of $795-million.

When the sinking-fund method of depreciation is used to calculate RCLD, the total RCLD estimate, including the GCV adder and physical severance costs, increases by approximately 25% to

$999-million as of year-end 2001. (See Figure 2-6.) Both RCLD values are used in our overall analysis of the estimated benefits and costs of municipalization in chapter 4.

Figure 2-6



e. State Board of Equalization RCNLD Valuation

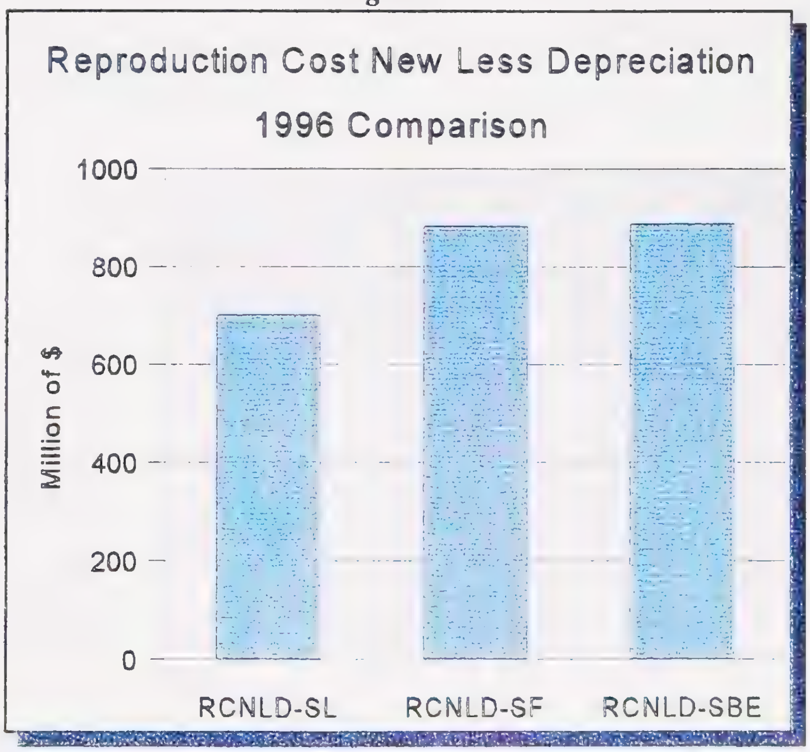
The California State Board of Equalization (the Board) is the agency charged with the responsibility of valuing the assets of corporations that are located in more than one county within the state. The purpose of the Board's valuation process is to: 1) determine a total state-wide assessed value for the corporation; and 2) allocate assessed values to various counties for the purpose of calculating property taxes on the assets located in each county. Each county must use the State Board of Equalization's assessed value in calculating property taxes.

Each year, PG&E transmits to the Board a list of the original cost of its electric, gas and common plant and equipment, geographically segregated by county. The Board takes this list of property and equipment, at original cost, and calculates Replacement Cost New Less Depreciation

(RCNLD). The calculated RCNLD value is then reduced down to an assessed value for the purpose of calculating PG&E property tax within each county. The original-cost data submitted by PG&E to the Board is not public information, nor is its calculation of RCNLD. However, the results of the RCNLD calculation for each category of PG&E electric, gas and common plant is public information. We analyzed the Board's publicly available data for PG&E, and we estimate that the RCNLD value, for PG&E's distribution system in San Francisco (excluding the SF generation assets) is approximately $767-million as of 1996, not including GCV or PS.

Figure 2-7 contains a comparison between the RCNLD values calculated by ETAG and ETAG's estimate of the State Board of Equalization's 1996 RCNLD value (including GCV and PS) for 1996 (RCNLD-SBE). ETAG's estimate of the 1996 Reproduction Cost New Less Straight Line Depreciation (-SL) is $701.5-million, and for the sinking-fund method of depreciation (-SF) the 1996 value is $881.8-million. ETAG's estimate of the 1996 Reproduction Cost New Less Depreciation, based on the valuation performed by the State Board of Equalization for 1996, is $887.5-million, including GCV and PS. Based on our knowledge of the depreciation method used by the State Board in its determination of RCNLD, we believe its a hybrid between straight-line and economic depreciation. Therefore, we conclude that, compared to the State Board's RCNLD valuation of PG&E's electric distribution, ETAG's estimate of RCNLD is reasonable and more than likely a low estimate of an actual RCNLD value.

Figure 2-7

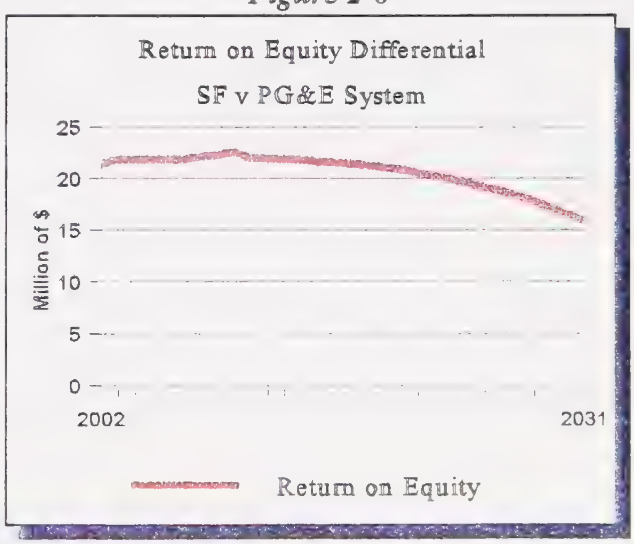


D. Income Method of Valuation

The income-capitalization method of valuation is based on the principle that the value of an asset is the steam of annual net incomes it generates for its owner over its remaining useful life. In the case of PG&E's SF distribution system, the income method of valuation would produce a value approximately the same as net book value if PG&E's equity return on its investment in SF was equal to the system-wide return on equity. However, we estimate that, under the electric-industry restructuring, PG&E actually will earn a return on equity in SF above the system-wide average return on equity because system-wide average distribution costs, which are higher than those in SF, are the bases for making rates for all PG&E electric ratepayers.

In order to calculate the "above"-average return earned in SF, we prepared a long-term forecast of the net return on common equity for SF and the PG&E system as a whole starting in the year 2002. Figure 2-8 contains a summary of the differential between the average system return on equity and the return earned in SF for the period 2002 through 2031. This stream of differential equity returns is then discounted back to the year 2002 at PG&E equity return of 11.6%. The net present value of the additional equity return earned by PG&E in SF as of 2002 is $183-million. This net present value amount is added to the SF estimated net book value as of year-end 2001 to produce a net-income-method estimated value of $500-million. Physical severance costs of $5-million was then added to the $500-million to produce a total of $505-million. The $505-million net-income-method value is carried forward to chapter 4 cost/benefit calculations.

Figure 2-8



E. Other Valuation Methods

One additional valuation method to be considered is comparable sales. There were no comparable sales that could realistically be used to arrive at a transfer price for the SF distribution system. Therefore, we cannot present any data or estimates of the value of PG&E's SF distribution system based on the comparable sales method of valuation.

We have also reviewed an estimate of RCNLD, as of year-end 2001, based on the PG&E RCNLD valuation performed in 1982. PG&E calculated a RCNLD value of $795-million as of year end 1982. We escalated this value from 1982 to 2001 at our long-run escalation rates. The result is a RCNLD value much higher than our own which uses economic depreciation.

F. Other Task 2 Issues

1. The Cost of Capital

In this study, ETAG is required to estimate the cost of borrowing for a CCSF municipal entity and overall cost of capital for PG&E. Our estimate for the cost of PG&E capital is presented in Table 2-2 on the next page. The cost of capital for PG&E that we used in our analysis, is the "gross weighted cost of capital" of 13.58%, which includes an allowance for state and federal income taxes. The 13.58% value was based on the stipulation among all participants in the CPUC's most recent cost-of-capital proceeding and was calculated as shown in the table.

In the case of municipalization, the bonds issued to finance the acquisition of PG&E's SF distribution system will have an effective interest rate of 7.5%. This rate is the average current rate for a taxable bond and is about 150 basis points (1.5%) above the current "tax-free" municipal bond rate. Our review of the Internal Revenue Code shows that since 1986 the federal income-tax

regulations severely restrict the purposes for which "tax-free" municipal bonds can be issued (IRS Code Section 141). Current IRS regulations would not allow CCSF to issue municipal bonds which are free from federal income tax for the purpose of acquiring PG&E's SF distribution system, but they are available for subsequent refunding and expansion financing. In all the cases that are summarized in chapter 4, we have assumed that tax-free bonds cannot be issued for the purpose of acquiring the distribution assets of PG&E.

Table 2-2

Calculation of

PG&E's Weighted Cost of Capital

Component	*Ratio*	*Cost*	*Wt. Cost*	*Gross Multiplier*	*Wt Cost + Income Tax*
Long Term Debt	46.2%	7.52%	3.47%		3.47%
Preferred Stock	5.8	7.04	0.41	1.69	0.69
Common Equity	48.0	11.6	5.57%	1.69	9.41
Total	100.0%		9.45%		13.58%

2. Regulatory and Litigation Costs - Included in Chapter Five

3. Inventories and Working Capital - Included in Chapter Five

4. Exit Fees and Related Items - Included in Chapter Five

5. Condition of Assets and Major Near-term Repairs and Replacements

We have no reason to believe that PG&E's SF distribution and related assets are not in a useful and serviceable condition, and no records, documents or regulatory proceedings that we have reviewed in the course of this assignment or are otherwise aware of, indicate otherwise.

We have reviewed the PG&E's 1996 Test Year forecast of marginal cost that was submitted to the CPUC. In the accompanying workpapers, PG&E has indicated that there are no distribution-related capacity increases in SF for the period 1996 through 2004. In 2004, PG&E estimates that it will spend approximately $4.9-million on distribution capacity increases in SF[14]. This amount is in addition to the normal replacements and capital repairs performed on an ongoing basis, and has been included in the capital requirements and cash flow projections in chapter 4.

[14]PG&E 1996 Marginal Cost Workpapers - Chapter 6.

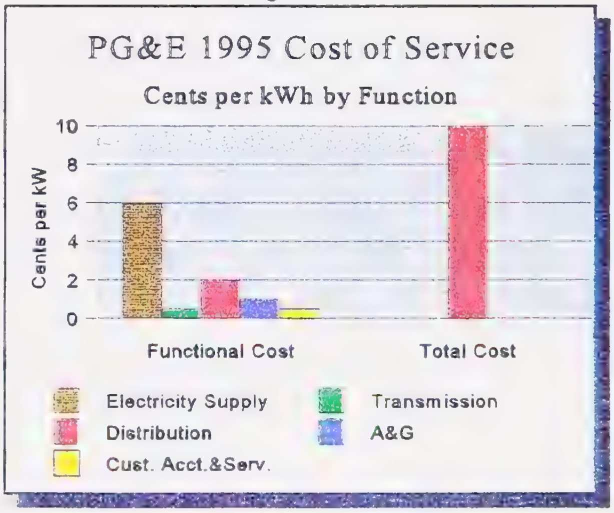
CHAPTER 3: Ongoing Costs of Owning and Operating an SF Electrical Distribution System

Overview and Summary of Chapter 3

Purpose and Scope

In this chapter, we present our analyses and forecasts related to the costs to supply (other than costs related to capital expenditures), transmit and distribute electricity in San Francisco (SF). The objective is to identify and quantify differences, if any, in: 1) power supply and transmission costs ; and 2) SF distribution system operating expenses between continued PG&E ownership (the BAU scenario) and takeover of the distribution system by a municipal electric utility (the muni scenario or option). The results of our analyses for the cost factors covered in this chapter are carried forward to chapter 4, where the total net benefit or costs of municipalization are calculated.

Figure 3-1



To provide a perspective on the issues addressed in this chapter, we prepared Figure 3-1 based on PG&E's 1995 recorded results of operations.[1] Figure 3-1 contains a breakdown of PG&E's avearge cost per kWh by function. Electricity supply, which includes the cost of owning and operating PG&E's generating stations and

[1] This estimate of PG&E's 1995 cost of service is based on data taken from its 1995 Annual Report to the CPUC.

purchased power costs, is by far the largest single component of PG&E's current cost of electricity: about 6 cents per kWh,[2] or 60% of the total current cost per kWh. The second largest component of PG&E's cost of service, at about 20% of the total, is the cost of owning and operating local distribution and related facilites in SF. Customer accounting, billing and services represents 5% of the total cost, and administrative and general expenses accounts for 10%. Bulk power transmission, at about 5% of the total cost of electricity, accounts for the remainder. In this chapter, we present the results of our analysis of each of these components of the cost of service and explain how and why these costs would or would not be materially different if a municipal electric utility was established by the City and County of San Francisco (CCSF or The City).[3]

Results of Analysis

a. Power Supply Costs

Power supply costs, which includes the costs of generating and purchasing bulk power and transmitting that bulk power from the generating site to SF, represent, by far, the largest component of the total cost of electricity. PG&E's current costs of owning and operating its electricity generation and transmission system and purchased power costs represent about 65%[4] of the total cost of providing electric service. PG&E's energy-supply costs are about 50% higher than the national average energy-supply costs. Reducing these high electricity supply costs via municipalization, if possible, could have provided significant benefits to electric ratepayers in SF before the advent of restructuring of the electric utility industry in California. However, as discussed in section 3.A, restructuring in California will dramatically change electricity supply costs for PG&E ratepayers over

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[2] This result is consistent with the California Energy Commission staff estimate of 5.98 cents per kWh that was presented in its August 27 filing in the ER 96 Committee Hearings.

[3] Since CCSF's costs of acquisition of the SF distribution and related facilities was estimated in chapter 2, the distribution costs estimated in this chapter relate solely to distribution operations and maintenance expenses.

[4] This value represents the total of 6 cents per kWh for electricity supply and 0.5 cents for bulk power transmission costs out of a total 1995 average cost per kWh of 10 cents. See Figure 3-1. Electric restructuring will lower these costs.

the next few years. PG&E and the other California investor-owned electric utilities will eliminate the difference between the "market price" of electricity supply and their own electricity supply costs and they have announced plans to sell off a significant portion of their fossil-fueled generating assets. In addition, restructuring will allow retail electric ratepayers to "bypass" PG&E's electricity supply and contract directly with alternative (non-PG&E) electricity suppliers. Direct access to alternative suppliers of bulk power will be available to many PG&E electric ratepayers by 1 January 1998, and all ratepayers will have the ability to choose their power supplier by 1 January 2002.

Our analysis in section 3.A of California's changing electricity supply market leads us to conclude that there is no credible evidence to suggest that future electricity supply costs to SF ratepayers will be significantly different whether or not a municipal electric utility established in SF. To the contrary, the most reasonable expectation is that these costs will be the same for both options.

b. Distribution System Operating Expenses

Distribution system operating expenses, not including creating and maintaining an energy-supply portfolio, can be broken down into two major cost categories as follows:

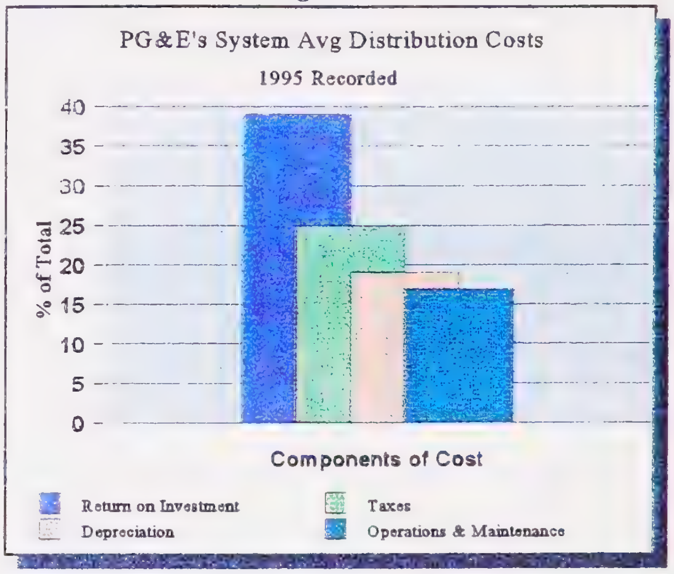
- Distribution-system operation and maintenance (O&M) expenses; and
- Administration, general and overhead (AG&O) expenses, and customer accounting, billing, information and other services (CABIS).

Distribution O&M expenses represent only a small portion of the electric customers' total current annual PG&E bill -- less than 4%.[5] Figure 3-2, on the next page, contains a breakdown of PG&E's system-average distribution costs by component of cost. The electric distribution function is characterized as "capital intensive" -- i.e., very high capital costs relative to operating costs. As shown in Figure 3-2, costs related to the capital investment in PG&E's electric distribution system

[5] 1995 Annual Report of PG&E to the CPUC.

(return, taxes and depreciation) account for nearly 85% of its total distribution costs.[6] O&M represents about 15% of the total or only about 3 mills (3/10 of a cent) per kWh out of a 1995 average PG&E rate per kWh of nearly 100 mills (10 cents) per kWh.

Figure 3-2



In section 3.B, we find that PG&E's distribution O&M expenses in SF are lower (by about 12%) than PG&E's system-average distribution O&M expenses. PG&E's electricity rates are based on system average costs, and therefore do not reflect the fact that local distribution O&M expenses are usually higher or lower than the system average. Thus, the creation of a municipal electric utility in SF could provide the equivalent distribution operations and maintenance services at a lower cost to electric ratepayers in SF than that charged by PG&E. However, this cost savings would only represent 1/2% (0.48%) of the total cost of electricity billed to the average customer (about $7.08 per year in 1996).[7]

AG&O and CABIS[8] represent about 12% (now) to 15% (post-restructuring) of the typical electric customer's total annual PG&E electric bill. O&M, AG&O and CABIS are three of the four primary functions that a CCSF municipal electric utility will take over from PG&E, with energy supply being the fourth. In section 3.B, we estimate that AG&O expenses could be lower if a municipal electric utility were to take over PG&E's SF distribution system. AG&O expense

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[6] The data in figure 3-2 was calculated by ETAG based on data taken from the 1995 Annual Report to CPUC.

[7] This was calculated as 4% (distribution fraction of total rate) x 12% (reduction in distribution costs) = 0.50%. The average system PG&E distribution O&M cost per customer, in 1996, is estimated at $59.78 per customer year. This estimate is based on the 1995 FERC 1 filing and PG&E's test -year cost-of-service filing before the CPUC.

[8] Customer information and services includes Demand Side Management expenses. DSM is, by far, the largest component of this cost item.

represents the cost of managing key utility functions such as O&M and customer accounting, billing information and service. Because we estimate that the overall cost of these functions will be somewhat lower in a SF municipal electric utility, as compared to PG&E's system-average cost, the AG&O expenses for the SF municipal electric will be correspondingly lower.

It could be argued that there will be some dis-economies of scale for the municipal electric option in the areas of customer accounting and customer services. PG&E sends out 4.5-million combined electric and gas bills per month, versus only 334,000 in SF. However, a CCSF municipal electric could combine its monthly meter reading and billing activities with the CCSF water department (realizing an economy of scope), and the billing cycle could be sized to minimize costs for these tasks. Therefore, we have assumed that customer accounting and billing costs will be the same for an SF municipal electric utility and for PG&E. We have made a similar assumption -- i.e., that there will be no dis-economies of scale -- in the area of customer services and information. The majority of customer service and information costs are related to Demand Side Management (DSM) expenses. While the focus of the DSM effort may change with municipalization, we have forecasted that the level of effort (dollars spent) will remain the same, on a per-customer basis. The net result is that we expect that there will be only minor differences in the net aggregated cost of those items (AG&O and CABIS) between continued PG&E ownership and a CCSF muni electric system.

Beyond economies of scale and scope, there remains the question of inherent operating efficiency differences, if any, between the muni option and monopoly-franchised, regulated IOUs (i.e., not private firms operating in competitive markets, but instead similar to PG&E's BAU service). Section 3.B includes an extensive review of the literature on this matter, culminating in our conclusion that there is no evidence to support claims of advantage for either option relative to the other (although both are less efficient than service by competitive markets). A number of studies address muni/IOU performance, showing a range of results and conclusions, with substantial fractions finding in favor of munis, in favor of IOUs, and no difference; in view of this distribution, a nominal score is spurious, and the only reasonable conclusion is no difference. Moreover, when confined to those studies that address electric-utility distribution operations, the results are again mixed, even

though the tally nominally favors IOUs. Our conclusion from this review and our own direct estimates in chapter 1, is that the reasonable assumption (and one that perhaps gives the benefit of any minor doubt to the muni option) is no difference.

The final function CCSF would take over from PG&E is the creation and maintenance of an energy-supply portfolio, including procurement from the power exchange (PX), as discussed above. Because it is and will remain well over half the total electric cost, any projected differences between PG&E's continued operation of the SF distribution system and a municipal electric utility in the areas of O&M, AG&O and CABIS is likely to have a relatively small impact on the overall net benefits and cost of municipalization. The SF municipal electric utility would have to include in its rates the cost of operating and maintaining the underground 230 kv SF cable distribution system. PG&E includes this cost as part of its total system costs, and therefore it is included in cost of service for all PG&E electric ratepayers.

c. Taxes Other Than Income Taxes

PG&E pays The City franchise fees on electricity revenues generated in SF and property taxes on the electric distribution plant and equipment located in SF. These two items total about $12-million per year.[9] While it is possible that The City could decide to raise this level of taxes from other sources, we believe that it is appropriate, for the purposes of analyzing the benefits and costs of municipalization of the PG&E electric distribution system, that these taxes continue to be included in a part of the cost of service, whether or not muncipalization occurs.

Risk Factor

As noted in chapter 2, we have assumed that a SF municipal electric utility will not have to acquire and operate the Hunters Point and Potrero generating stations, which provide electric

[9] Source of this estimate is explained in chapter 5.

reliability services only to SF. In the electricity-supply forecast prepared by the California Energy Commission's consultant[10], these SF reliability costs are spread over all of PG&E's service territory. However, if a separate electric-utility service territory is created in SF through muncipalization, then this may result in the direct allocation of these SF reliability cost directly to SF electric ratepayers. On the other hand, the better argument is that, if such "de-averaging" is to be done, it should be done generally and on its own merit -- and thus, under sound policy development, it is not really attributable to municipalization (although that may precipitate it). We estimate that the annual O&M costs for these reliability units is about $10-million per year in 1996 dollars. Details on the capital and operating costs of the SF generating units can be found in the workpapers for chapter 2 (WP-2).

Organization of Chapter 3

The remainder of this chapter consists of a detailed explanation of the analysis and assumptions used to by ETAG to arrive at the conclusions presented above. Section 3.A deals with power supply issues. Section 3.B presents our analysis of other forecasted operating expenses.

A. Power Supply Costs

1. Background

For most of its corporate life, PG&E, like most other major private and public electric utilities, built, owned and operated electric power stations to meet most of its customers' demand for electricity. Historically, PG&E's portfolio of electricity supply also included purchases from other electric utilities. The total annual cost of owning and operating its generating stations and purchasing power from other utilities was passed on to the electric ratepayer through the ratemaking process at

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[10] California Energy Commission, Lotus Consulting Group forecast prepared for the August 1996 ER-96 Committee Hearings.

the CPUC. Electric ratepayers, within PG&E's service territory, could not avoid PG&E's power supply costs because there was no competitive market in electricity supply, and ratepayers were not allowed access, through the PG&E transmission system, to alternative electricity suppliers. The only exception to this rule was the case in which individual ratepayers would "self-generate" all or portion of their electricity requirements.

This "non-competitive" system of electricity supply was the norm in California and throughout the nation, and it generated little controversy in the past. Up until the middle and late 1970s, California's investor-owned utilities (IOUs), including PG&E, had power-supply costs that were as low as or lower than other IOUs in the region and lower than the national average.[11] However, due to a number of factors, the California IOUs' electricity supply costs began to increase to the point were they are now about 50% above the national average.

In response to this cost problem, the CPUC initiated a process to restructure California's IOUs. During the same time frame, the Federal Energy Regulatory Commission (FERC) was considering policy changes to encourage competition through "equal access" to the IOUs' transmission systems for wholesale sellers of bulk electric power.

2. Creation of a Competitive Electric Supply Market In California

In December 1995, the CPUC released a final decision ordering the restructuring of investor-owned electric utilities in California, including PG&E, and retail competition in electric power supply. The stated key policy objectives of the CPUC's restructuring policy are as follows:

- Reduce electric ratepayers bills;
- Create a competitive power supply market; and

[11] 1977 PG&E Annual Report to stockholders. Until the oil "crisis" of the 1970s, natural-gas-fired electric was competitive with coal-fired generation, and hydro power represented a greater proportion of PG&E's total electricity supply than it currently does.

- Permit energy-supply market competition by allowing retail customers to choose between continued electricity supply by the local electric distribution utility and any other provider.

FERC, in early 1996, issued its policy directive on wholesale wheeling and market competition (Order 888). The California Legislature passed AB 1890 and the Governor signed the bill in September 1996. AB 1890 enacts into law most of the CPUC's electric restructuring provisions and adds the following elements to the restructuring program:

- It mandates for a 20% reduction in residential and small commercial electricity rates.
- It authorizes "direct access" by retail customers to any producer of electricity. Phased-in "direct access" program begins no later than 1 January 1998. All retail customers will have direct-access rights by 1 January 2002.
- It permits customers to voluntarily aggregate their electric loads and participate in "direct access" electricity supply transactions on an aggregated basis. Aggregation can be provided by private market aggregators, cities, counties and special districts.
- It authorizes a "Competition Transition Charge" (CTC) whereby California's IOUs will write-off the difference between the cost of their electric generation resources and existing purchase power contracts and the market value of those generating assets and purchase power contracts. The CTC will be greatly reduced by 31 December 2001.[12]
- It forecloses cities and counties' ability to avoid the CTC through muncipalization.

3. Implications of Restructuring on Municipalization

The restructuring of California's electricity markets will eliminate most or all of the possible advantages that muncipalization could have produced in the area of electricity supply. As shown in Figure 3-1, above, the cost of electricity supply is the dominant cost: 60% of PG&E's total average

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[12] There will be an ongoing CTC after 2001 for certain power purchase contracts and Diablo Canyon O&M costs. Ongoing CTC after 2001 are estimated to represent about 22% of the total CTC cost (PG&E Exhibit in A-No. 98-08-070 dated 21 October 1996, page EX-2). The portion through 2001 is called the "dog" and that after 2001 is the "tail".

cost of nearly 10 cents per kWh. By year-end 2001, PG&E's average cost of electricity supply will be reduced to approximately the market rate. Some might argue that, based on past performance, PG&E might, in the future, create a new "high-priced" portfolio of electricity supply, and that muncipalization is insurance against this possibility. The answer is that electric ratepayers in SF can avoid PG&E's electricity supply cost by becoming "direct access" purchasers of electricity supply. In fact, if CCSF found a cheaper source of electricity, it could access that supply for the benefit of the electric ratepayers in SF under the new rules governing electricity supply *without* having to establish a municipal electric utility. The City could establish itself as a direct-access provider as early as 1 January 1998. Hence, while CCSF may play a role in the future in helping secure low rates for San Franciscans, such role is entirely separate from the question of municipalization of PG&E SF electric-distribution system.

Other possible questions in the area of electricity supply involve "preference power" and the Hetch Hetchy electricity supply. Municipal electric utilities have preference claims on low-cost electricity produced by federal water projects, and such preference was a major stimulus to muncipalization in the past. However, the only possible source of preference power to a new CCSF municipal electric utility would be from the Central Valley Project. Virtually all of this relatively cheap electricity has already been allocated. Any new allocations that may be available in 2004 would serve only a tiny fraction of SF's annual electricity demand, or even of CCSF's own use. Thus, on this item, too, there is no prudent basis to estimate a muni-option electricity-supply cost advantage.

The economic value to CCSF of the Hetch Hetchy resource is currently optimized within its contractual, physical and environmental limits. Hetch Hetchy has long-term power sales contracts with the Modesto Irrigation District (MID) and the Turlock Irrigation District (TID), collectively, "the Districts". These contracts provide a mechanism for scheduling sales of "Raker Act" power.[13]

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[13] Power generated by Hetch Hetchy plants is sold to MID and TID at cost for agricultural pumping and municipal public power purposes (Class 1 Power) as mandated by the 1913 federal Raker Act, which granted The City rights of way to construct its water collection, conveyance and other facilities. Muni partisans have suggested that the Raker Act requires CCSF to operate a public-power authority to sell Hetch Hetchy power at retail to residents and perhaps businesses in SF. Certainly, it does not require this on its face, making no mention of it. Moreover, for over half a century, The City has

These contracts also provide that an additional increment of power will be sold to the Districts for other uses on a specified price formula. These contracts expire on 30 June 2015. However, the obligation under the Raker Act to provide Class 1 power at cost to the Districts continues indefinitely. Therefore, any benefit to SF by using more of Hetch Hetchy's electricity production within SF to serve SF retail loads would be offset by the requirement to purchase a similar amount of electricity at market rates to meet Hetch Hetchy's obligation to the Districts.

4. Conclusion

Based on our analysis of the changing power supply markets in California, we conclude that there are not likely to be any material benefits to electric ratepayers from lower electricity supply costs, whether or not a municipal electric utility is created in SF. One could assume that either the SF muni or PG&E could create a power supply portfolio that is more or less expensive than the forecasted market price. However, we would have no basis for making such a projection, and thus we have not done so in our analysis.

B. Operating Expenses

1. Distribution Operations and Maintenance Expenses

Distribution-system O&M expenses include the labor and material required to keep the distribution system in a safe, reliable and efficient working condition. Included in distribution

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successfully defended and implemented a position to the contrary, recognizing that, as concerns Hetch Hetchy power, the Raker Act mainly prohibits sale of electricity to private utilities (IOUs) for resale and supports some public-agency preferences for that electricity. Opinions by CCSF's City Attorney (e.g., a 29 October 1971 letter from Thomas M. O'Connor, then City Attorney, to Edward R. Sherwood, Acting Foreman of a Grand Jury) have recognized that the decisional language from a 1940 case on which the partisans have hung their hats, (claiming, "It's the law.") is dictum, not law. Hence, our analyses being consistent with established, sound City policy and the fact that this study does not depend on Raker Act provisions, we have not addressed the Raker Act further in this report.

expenses are the O&M of substations, overhead and underground distribution lines, customer revenue meters, services and street lights and signals. In order to calculate the overall net costs or benefits of municipalization, ETAG had to forecast distribution O&M expenses that PG&E "actually"[14] incurs in SF and PG&E's system-wide average distribution O&M expenses used in the ratemaking process.

The basic sources of data for PG&E's O&M expenses are the annual FERC Form 1 filings and PG&E's 1996 test-year cost-of-service study filed with the CPUC. Based on an analysis of this data, we calculated a 1996 average system cost of approximately $59.80 per customer per year. We reviewed each component of O&M to determine if an adjustment was needed for the unique conditions (urban setting and concentrated loads) which exist in SF. We made a minor adjustment to operating expenses and material adjustments to maintenance expense. The net result is that we estimate that the average cost that PG&E actually incurs in SF is approximately $52.70 per customer per year for O&M expense. On a total-dollar basis, we estimate that PG&E's actual O&M expense for the SF distribution system in 1996 is about $17.6-million. This compares with a system-average allocation of O&M expenses to SF, through the ratemaking process, of $20.1-million. Therefore, we estimate that distribution O&M expense could be reduced by about 12%, or $2.5-million per year in 1996 dollars, under the muncipalization scenario.

Offsetting this O&M cost advantage, to a small extent, is the cost of maintaining the 230 kv underground cable system, which is unique to SF. This cost is currently included in the PG&E's average system costs, and SF electric ratepayers pay only about 8% of this cost. If the PG&E distribution system is municipalized, 100% of this cost would be borne by SF electric ratepayers. We estimate that the incremental O&M on the SF transmission system is today about $600,000 per year.[15] Total distribution O&M is escalated by our long-run inflation factor of 2.5% and also by a SF customer growth factor.

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[14] The use of word "actual" is intended to distinguish ETAG's estimate of SF distribution O&M expenses from ETAG's estimate of PG&E's system average cost that is allocated to ratepayers within SF.

[15] This estimate is based on a marginal-cost study of transmission O&M costs which equates transmission O&M to average original-cost plant balances.

Beyond "de-averaging" effects, there is also the question of whether PG&E has an economy-of-scale advantage in operating the SF distribution system in conjunction with the rest of its system, as compared to the costs that CCSF would experience on its own. A paper titled, "Pricing in the Electric Power Industry: The Influence of Ownership, Competition and Integration"[16] found (page 14): "there is evidence of economies of scale in transmission and distribution in that [variables for line-miles of each] are negatively related to final price, although [the distribution variable] never quite achieves statistical significance." However, upon review of this paper (which looks quite good at first), we find a fundamental error that nullifies all of its findings and conclusions (even though many may ultimately be proven true by other means or a corrected version of this paper): its key common-stock profits variable has been defined and quantified (page 9) to include only dividends and to exclude the roughly one-third of total profits that go into retained earnings. For this reason, much more than for the failure to achieve statistical significance, we find it impossible to rely on this conclusion (which, nonetheless, comports with economic intuition).

2. AG&O and CABIS Expenses

As discussed in the introduction to this chapter, administrative, general and overhead (AG&O) and customer accounting, billing, information and (other) services (CABIS) represent about 12% (now) to 15% (post-restructuring) of the typical electric customer's total annual PG&E electric bill. These are the two of the four primary functions that a CCSF municipal electric utility would take over from PG&E. AG&O expense represents the cost of managing key utility functions. AG&O expenses include officers' salaries, property insurance, injuries and damages expenses, employee pensions and benefits, regulatory expenses, and the maintenance of general plant.

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[16] Paper, written by John E. Kwoka, jr., Professor of Economics, George Washington University and dated December 1993, was prepared for the American Economics Association session on "Regulation and Competition" in Boston in January 1994. The work was sponsored by APPA.

In our forecast of AG&O expenses for the SF municipal electric utility and PG&E, we use the same AG&O rate, 17%,[17] but because operating expenses of the SF municipal electric utility are expected to be lower due to "de-averaging" of the O&M component, the application of the same AG&O rate will produce lower forecasted AG&O costs (about 5% lower) for the municipal electric utility as compared to PG&E.

An item raised at page 31 of the APPA "Straight Answers to False Charges Against Public Power" paper, is executive salaries for IOUs -- an AG&O cost component. Indeed, as suggested in the paper, IOU top-executive salaries exceed those of munis. However, PG&E has a much broader customer and revenue base over which to spread these costs than would a CCSF muni, and they contribute on the order of 1/10th of one percent of its total electric operating costs (the exact amount depending on which employees are counted in the list). Our allowances for top-level salaries for a CCSF electric utility include comparable levels (i.e., on the order of 0.1%) for such costs for the City, meaning there would be no difference to ratepayers on this point. In any event, this item is de minimis for munis and IOUs, adding about six cents ($0.06) to a typical monthly customer bill of $75.00.

Customer accounting and billing includes the monthly cost of meter reading, recording, accounting and billing. Customer services and information includes a wide variety of customer services including answering customer billing and service inquires and providing energy conservation audits. In our analysis, we forecast that the CABIS costs will be the same for both the muni and PG&E. It could be argued that PG&E has an economy-of-scale advantage in customer accounting and billing due to the fact that its servers 4.5 million customers versus only 334,000 in SF, and an economy-of-scope advantage by combining electric and gas bills. However, we assumed that a municipal electric utility could provide this service at about the same cost. The SF municipal electric could combine operations with the water department in the areas of meter reading, customer

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[17] This estimate derived from FERC 1 filings.

accounting and billing. In addition, the monthly billing cycle could be sized to effectively offset any PG&E advantage in this cost area. For customer service and information, which are primarily expenses related to DSM programs, we assumed the same per-customer level of expense for the SF municipal electric as is forecasted for PG&E.

3. Relative Muni/IOU Operating Efficiency Assessment

William J. Hausman and John L. Neufeld in a paper titled, "Public Versus Private: A summary of the economic literature on the comparative performance of U.S. electric utilities", prepared October 1990 for APPA, examined studies of relative muni/IOU operating efficiency done over a 20 year period. Below is a list of the papers cited in this Hausman and Neufeld paper as either "The Recent Empirical Literature" or "Modern Analysis", not including those papers that do not address the question of IOU/muni efficiency. In particular, we highlight the conclusions of each paper as applied to electric distribution systems -- the issue here. On that basis, four of the studies support higher IOU efficiency, one supports higher muni efficiency, three show no difference, and five are not probative because they address electric generation, but not distribution. (Note: Hausman and Neufeld argued in their paper with some of the conclusions of the other papers, and sought to recast them, contrary to what the authors of those papers concluded about their own work. They did so while alleging bias by some other authors, which is remarkable, because their own work was expressly sponsored by APPA. Our account presents what the other authors themselves concluded, where that differs from the Hausman/Neufeld account, and we do not inject our own attempts to alter the conclusions, as they did.) We present the other studies in the order Hausman and Neufeld did.

- Anthony E. Boardman & Aidan R. Vining, April 1989, *Journal of Law and Economics*; "Ownership and Performance in Competitive Environments: A Comparison of the Performance of Private, Mixed and State-Owned Enterprises" -- This survey, widely cited, shows many more studies concluded that private electric service is more efficient than publicly-owned services, as compared to the number that concluded to the contrary or found no difference. **Results favor IOUs.**

- Peltzman, 1971 *Journal of Law and Economics*, "Pricing in Public and Private Enterprises: Electric Utilities in the United States" -- Also widely cited, as Hausman and Neufeld admit while challenging its conclusions, this paper concludes that private utilities are more efficient because publicly owned utilities mis-price service due to political pressure. **Results favor IOUs.**

- Louis DeAlessi, Fall 1974 *Public Choice*, "An Economic Analysis of Government Ownership and Regulation: Theory and the Evidence from the Electric Power Industry" -- This survey concludes that private utilities are more efficient. **Results favor IOUs.**
- Louis DeAlessi, 1975 *Economic Inquiry*, "Some Effects of Ownership on the Wholesale Prices of Electric Power" -- Although Hausman and Neufeld conclude that this article shows no difference, instead of an IOU advantage, the argument is mooted by the fact that this item addresses bulk-power supply, not distribution. **Results do not address distribution.**

- Thomas Gale Moore, April 1970 *Southern Economic Journal*, "The Effectiveness of Regulation of Electric Utility Prices" -- In the words of Hausman and Neufeld, this statistical analysis which addressed residential electric rates, "found a significant difference in favor of privately owned firms." **Results favor IOUs.**

- James A. Yunker, Fall 1975 *Journal of Economics and Business*, "Economic Performance of Public and Private Enterprises: The Case of U.S. Electric Utilities" -- Hausman and Neufeld state, "the basic conclusion from this investigation would have to be that no significant ownership effects were found." **Results favor neither -- i.e., favor ETAG's usage.**

- Robert A. Meyer, November 1975 *Review of Economics and Statistics*, "Publicly Owned versus Privately Owned Utilities: A Policy Choice" -- Again, in the words of Neufeld and Hausman, this study found, "no significant ownership differences for transmission and distribution costs." **Results favor neither -- i.e., favor ETAG's usage.**

- Leland G. Neuberg, Spring 1977 *Bell Journal of Economics*, "Two Issues in the Municipal Ownership of Electric Power Distribution Systems" -- This paper reports a 6% to 26% rate advantage for munis. ETAG's 6.4% base-case results in this study lie within this range; in fact, when the 55% of production and transmission costs are set aside, as Neuberg did, ETAG's base-case margin is 14.2%, which lies squarely in the mid-range of these results. **Results favor munis -- and they very much support ETAG's results.**

- Donn R. Pescatrice and John M. Trapani, April 1980 *Journal of Public Economics*, "The Performance and Objectives of Public and Private Utilities Operating in the United States" -- As Hausman and Neufeld state, "Data were gathered for the generation of electricity only." **Results do not address distribution.**

- Thomas J. DiLorenzo and Ralph Robinson, Summer 1982 *Quarterly Review of Economics and Business*, "Managerial Objectives Subject to Political Market Constraints: Electric Utilities in the U.S." -- This study considers generation costs only, and as Hausman and Neufeld state, "the dummy variable representing ownership was not significantly different from zero" -- meaning that statistically, this study showed no advantage to either side. **Results do not address distribution.**

- R. Fare, S. Grosskopf and J. Logan, February 1985 *Journal of Public Economics*, "The Relative Performance of Publicly-Owned and Privately-Owned Electric Utilities" -- This study also considers generation only, and finds, per Hausman and Neufeld, "No significant difference in overall efficiency." **Results do not address distribution.**

- Scott E. Atkinson and Robert Halvorsen, April 1986 *Journal of Public Economics*, "The Relative Efficiency of Public and Private Firms in a Regulated Environment: The Case of U.S. Electric Utilities" -- This study also addresses generation only and finds, per Hausman and Neufeld, "No significant differences in efficiency." **Results do not address distribution.**

- Daniel R. Hollas and Stanley R. Stansell, October 1988 *Southern Economic Journal*, An Examination of the Net Effect of Ownership Form on Price Efficiency: Proprietary, Cooperative and Municipal Electric Utilities" -- Hausman and Neufeld begin their review of this item with: "This study used the most recent data and modern methodology to conclude that privately owned utilities were more efficient than were municipally owned utilities." It concludes, "Although flawed, the study by Hollas and Stansell was the only one to use data less than twenty years old." Unfortunately, it did not address distribution. **Results do not address distribution.**

This is not an exhaustive list of the studies in this area, but it is a representative one -- and one developed in an APPA-sponsored review.[18]

In its monograph, "Straight Answers to False Charges Against Public Power" (at page 7), APPA cites the Kwoka paper discussed above for its conclusion that public ownership brings benefits in operating efficiency. As noted above, though, the results of this paper are based on an error that renders all of them, by the nature of the multi-variate statistical methods used to get them, unsupported (even though correction of the error may later reveal some of the particular conclusions

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[18] During the review process for this project, some partisans urged upon us numerous documents and points from APPA for review and reliance in this report -- but none from the Edison Electric Institute (EEI), APPA's institutional opposite for these purposes. We reviewed them thoroughly, and concluded that parts support the analyses here and parts do not; moreover, as shown in the response in this report to all significant items, some of them are right and some are wrong. We also gave direct answers in the review process to all such partisan points and sources raised. Likely, we would have reached the same conclusions concerning material from EEI, had the review process included any partisans from that side. While we have addressed the important items, space limits preclude discussion of all such sources and points in this report.

An example of the many points we answered during the process is the claim that munis keep ratepayers' dollars in the local community, while IOUs pay them elsewhere in stockholder dividends. This notion ignores the fact that every dollar not financed by stock is financed by debt, and muni debt-holders are at least as widely distributed away from the local community as are IOU stockholders (and maybe more so, being more institutional than individual holdings than is IOU stock), and thus munis pay as much or more to distant investors as do IOUs per dollar of rate base. In addition, the muni SF rate base (acquisition cost for the system) will exceed that for PG&E, meaning that the total number of dollars exiting the community would be much greater for the muni option. An example of a partisan claim that is correct is that there is a difference between what IOU ratepayers get for their money and what muni ratepayer/taxpayer/owners get for theirs. We think we have given more substance in our explanations and effect in our numbers to this point than have the partisans.

to be basically correct). In particular, the public-ownership efficiency conclusion is highly suspect, as well as lacking support, for it is based on a residual savings in the equations which appears to be directly inflated by the error discussed above (systematic understatement of the IOUs' profit levels). Kwoka has also written two subsequent papers which are derivative of this first paper ("Ownership, Competition, and Price Performance of Electric Utilities", October 1994; and "Public versus Private Ownership and Economic Performance: Evidence from the U.S. Electric Power Industry", February 1995) and which incorporate the same completely disabling error. As noted above, but for this problem, the concept of the Kwoka paper is very attractive, for it attempts to provide the definitive study on the relative efficiency issue, as well as others such as economies of scale. We requested an explanation from Kwoka for his usage (profit measure error), and he said he would contact us if he had something to offer in its defense -- but he has not done so in over two months.

APPA has also recently published a paper by MSB Energy Associates, *Explaining Public Power's Low Rates: A Critical Review of the EEI-Sponsored Report: "Subsidies and Unfair Competitive Advantages Available to Publicly Owned and Cooperative Utilities,"* dated 5 April 1996. This paper is fundamentally wrong in its key attempts to refute another analysis. As an example, it makes incorrect adjustments to IOU deferred taxes, the ratemaking consequences of which were correctly recognized in the other study. The EEI paper to which it responds showed a 4% IOU efficiency advantage -- but, again, we did not adopt such a position.

Another item, representative of the APPA paper, "Straight Answers ...", is its use at page 4 of results in an article titled, "Property Rights Versus Public Spirit".[19] APPA quotes the authors' results by saying that they "constructed several measures of productive efficiency ... We found for every measure examined the municipally owned electric utilities were significantly more efficient than their privately owned counterparts." Nothing in the APPA paper indicates the fact one learns upon consulting the original source: that it is based on data from a century ago (1897-1898), specifically in order to study effects without (before) utility regulation, and that it has absolutely nothing to do

[19] Article was written by William J. Hausman and John L. Neufeld and published in the *Review of Economics and Statistics*, 1991, pages 414-423.

with modern utilities -- to which APPA appears to suggest the results apply. At one level, all this study does, in fact, is to show that unregulated private natural monopolies did what unregulated monopolists do: reap "excess" profits. But that's irrelevant to municipalization issues today, because there are no longer any such unregulated private electric monopolies -- and the real choice (as focused here) is between public power and state-franchised and -regulated IOUs.

4. *Annual Depreciation Expense Forecasts*

Annual depreciation expense is dependent on the level of capital investment in depreciable plant and equipment. Therefore, the forecasted annual depreciation expense in the municipalization scenario will depend on the price paid for the PG&E distribution system. Over time, as the acquisition cost of the PG&E distribution system is amortized and new plant and equipment additions are made to the SF distribution system, any differences in depreciation expense between the municipal electric and the PG&E will become relatively small. The transfer price or value of the PG&E distribution system is presented in chapter 2, and the forecasts of depreciation expense are presented in chapter 4 of this study, based on the transfer-price valuations.

CHAPTER 4: Cost/Benefit Analysis

Overview and Summary of Chapter 4

In this chapter, section 4.A pulls together the cost elements and other factor estimates developed in chapters 2 and 3 into an overall assessment of the economics of municipalizing PG&E's electric-utility service in SF. Those two chapters explain assumptions regarding the cost elements and other factors for our three cases (base, low- and high-cost) and each of the two scenarios (municipalization and business as usual, or BAU -- i.e., continued PG&E service). Figure 4-1 on the next page summarizes these assumptions. Section 4.B addresses other economic and policy issues, including the role of non-income taxes PG&E pays, possible job losses due to PG&E moving its headquarters out of SF in response to municipalization, CCSF's contracts with PG&E for transmission, reliability and ancillary services, working-capital and initial-inventory requirements. At the end of the chapter, we address the decision criteria to be used for the municipalization question, present a "what if" sensitivity analysis, and assess internal cash-flow and financing issues.

The scope of work in the contract for this project calls for an ultimate conclusion on the likely economics of municipalization in terms of its effect on electric economics in SF. It requires that we specify one of the following ranges as characterizing the likely economic effects:

- A decrease in costs of zero to 5%;
- A decrease in costs of 5% to 10%;
- A decrease in costs exceeding 10%; or
- An increase in costs.

We present two analyses to answer this question. First, we estimated annual rates and revenues for each of the two (muni and BAU) scenarios in each of the three cases. From these data, we computed the net present values (NPVs) of savings from municipalizing PG&E's electric service

Figure 4-1
Assumptions Used by ETAG's CCSF Muni Preliminary Feasibility Study

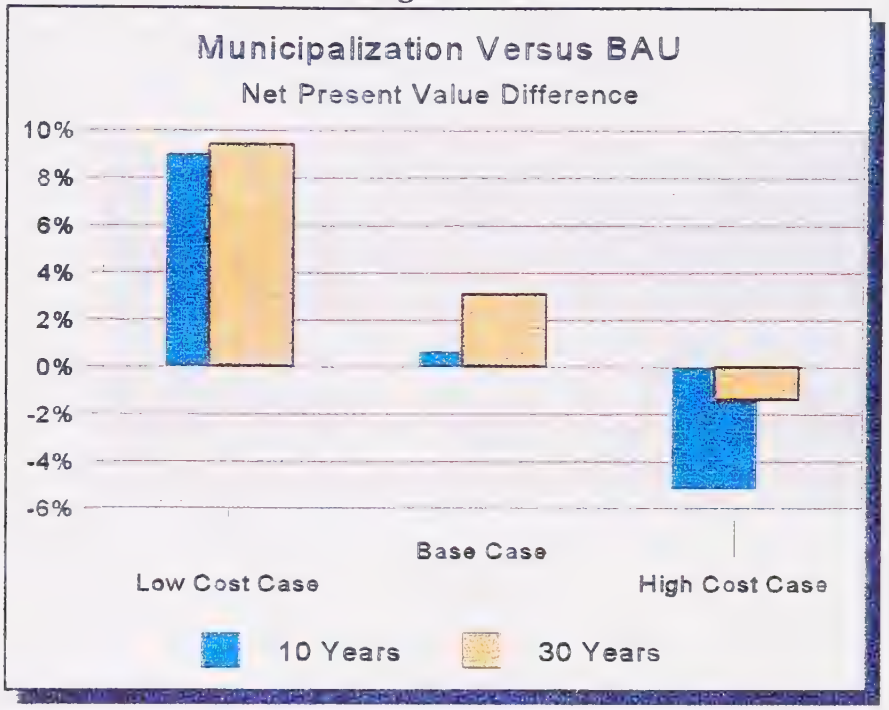
Cost Item	*BAU*	*Municipalization Case*		
	Data Sources	*Low Cost*	*Base Cost*	*High Cost*
1. Distribution O&M	1996 Test Year Forecast as Filed at CPUC	12% Lower than BAU-ETAG Estimate	Same as Low Cost Case	Same asLow Cost Case
2.a. Power Supply	CEC UPLAN Forecast - Starts at $31.24/MWh in 2002	Same As BAU	Same As BAU	Same as BAU
2.b. CTC	Estimate Based on PG&E CTC Filing at CPUC	Same As BAU	Same As BAU	Same as BAU
2.c. SFOC	Energy Commission UPLAN Forecast	Same As BAU	Same As BAU	Same as BAU
2.d. Transmission	Estimate Based PG&E FERC Filing	Same As BAU	Same As BAU	Same as BAU
3.a. Franchise Fees	0.5% of Gross Revenues	Same As BAU	Same As BAU	Same as BAU
3.b. Property Tax	Assessed Value	Same As BAU	Same As BAU	Same as BAU
4. Customer Accts +Service & Information	Historic Data from FERC1 1990-1995	Same As BAU	Same As BAU	Same as BAU
5. A&G Expense	Historic Data from FERC 1 1990-1995 = 17% of O&M, Cust Accounting & Cust Info.	5% Lower Than BAU	Same as Low Cost Case	Same as Low Cost Case
6.SF- UG Cable O&M Expense	SF - UG Cable Cost Averaged Over PG&E System Cost	1.18% of Original Cost	Same as Low Cost Case	Same as Low Cost Case
7. Depreciation	System Average Distribution Plant Depreciation	SF NBV Depr.+ 20 Year Amort. of (Valuation - NBV)	Same as Low Cost Case	Same as Low Cost Case
8. Amort. of Development Costs		20 Year Amort. Period (see chapter 5)	Same as Low Cost Case	Same as Low Cost Case
9. Cost of Capital	13.58% for PG&E From CPUC 1996 Rate of Return Proceeding	7.5%	Same as Low Cost Case	Same as Low Cost Case
10. Valuation Year End 2001	Average System Investment per Customer x SF Customers	$505-million	$794.5-million	$999.5-million
11. SF Peak and Energy Forecast	PG&E Filings at CPUC and CEC	Same As BAU	Same As BAU	Same as BAU
12. Inflation	2.5% Long-Run ETAG Estimate	Same As BAU	Same As BAU	Same as BAU

in SF, using data estimated for the first 30 years in the muni and BAU scenarios in each case. In sum, the results for this first method, the comparison of total rates, are:

- The net electric-rate benefit of municipalization in the base case (based on RCLD-SL valuation) is a long-run present value of about a 3% savings in rates; muni service costs SF ratepayers more in the first three years, and then yields increasing savings each year thereafter.
- The net electric-rate benefit of municipalization in the low-cost case (based on an income capitalization valuation) is a long-run present value of about 9% -- a roughly constant percentage each year.
- The net electric-rate extra cost of municipalization in the high-cost case (based on RCLD valuation using economic depreciation) is a long-run present value of about 1% higher electric bills; muni service starts at about 10% higher and the differential decreases slowly with time, becoming less expensive after the tenth year.

In terms of the ranges for expected outcomes specified in the statement of work, these results indicate that, based only on the total rates comparison, the most likely outcome is that rates savings would result from municipalization and that they would lie in the 0% to 5% range. This outcome is significantly more likely than any other, in our view. Second most likely is that they would fall in the 5% to 10% range, and third most likely is that there would be increased rates in the 0% to 10% range, instead of savings. We see no realistic chance the total-rates-based savings would exceed 10% and less likelihood that the possible extra rates costs of municipalization, if it turned out to be more costly than BAU would exceed 10% of the rates from PG&E. These figures include all costs that are covered in electric rates normally, including some miscellaneous items addressed in chapter 5. Please note that these net effects include payment for CCSF's acquisition costs for PG&E's SF electric-distribution system -- and thus CCSF would own these assets for the benefit of SF ratepayers and taxpayers, as well as reaping the various levels of rates savings estimated for them. Our basic conclusions, then, on the likelihood of the effects on rates falling in these four ranges is based on the data shown graphically in Figure 4-2, on the next page, which graphs in a bar chart the long-run NPV estimates of the rates differences in muni and IOU charges for each of our cases.

Figure 4-2



The direct effects of municipalization on electric-utility rates are detailed in Tables 4-1 and 4-2 on the next two pages. These two tables show for the years 2002 (the first year that municipal service could begin, as explained in chapter 5) and 2011 (reflecting the long-term effects of municipalization on rates) the comparison of rates for the two scenarios in each of the three cases (base, low-cost and high-cost), with a breakdown of the rates by the cost components. Total rates for each scenario in these two tables reflect the results summarized above on page 4-3, with Table 4-1 showing the initial effects and Table 4-2 generally reflecting the long-run present-worth results discussed above. In section 4.A here, we discuss these results in detail, connecting key assumptions of our analysis to particular results and determining which factors really drive the rates and economics of municipalization versus continued IOU service. The main results for total rates are:

1. The total-rates comparison differences are dominated by the valuation on the SF electric-distribution system that would be set in a condemnation action by CCSF against PG&E.

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Table 4-1
Comparative Cost Per kWh
For the Year 2002
Municipalization versus PG&E

	Base Case Transfer Price - RCNLD - SL Cents per kWh			Low Cost Case Transfer Price - Net Income Value Cents per kWh			High Cost Case Transfer Price - RCNLD - SF Cents per kWh		
Cost of Service	Municipal Costs	PG&E Costs	Difference	Municipal Costs	PG&E Costs	Difference	Municipal Costs	PG&E Costs	Difference
1. Power, Transmission & CTC	4.13	4.13	0.00	4.13	4.13	0.00	4.13	4.13	0.00
2. Distribution O&M Expense	0.47	0.54	(0.06)	0.47	0.54	(0.06)	0.47	0.54	(0.06)
3. Franchise Fees & Property Tax	0.15	0.15	0.00	0.15	0.15	0.00	0.15	0.15	0.00
4. Customer Accounts Expense	0.30	0.30	0.00	0.30	0.30	0.00	0.30	0.30	0.00
5. Customer Serv. & Info. Expense	0.26	0.26	0.00	0.26	0.26	0.00	0.26	0.26	0.00
6. Administrative and General Expense	0.18	0.19	(0.01)	0.18	0.19	(0.01)	0.18	0.19	(0.01)
7. SF 230 kv Cable O&M	0.02	0.00	0.02	0.02	0.00	0.02	0.02	0.00	0.02
8. Total Non-Energy Operating Costs	1.37	1.43	(0.06)	1.37	1.43	(0.06)	1.37	1.43	(0.06)
9. Depreciation - Plant and Equipment	0.89	0.58	0.31	0.56	0.58	(0.02)	1.12	0.58	0.54
10. Amort. of Development Costs	0.03	0.00	0.03	0.03	0.00	0.03	0.03	0.00	0.03
11. Cost of Capital on Basis Difference*	0.55	0.00	0.55	0.08	0.00	0.08	0.87	0.00	0.87
12. Subtotal	1.46	0.58	0.88	0.66	0.58	0.09	2.02	0.58	1.44
13. Cost of Captial on PG&E SF Rate Base	0.81	1.02	(0.21)	0.81	1.02	(0.21)	0.81	1.02	(0.21)
14. Income Taxes, State and Federal	0.00	0.45	(0.45)	0.00	0.45	(0.45)	0.00	0.45	(0.45)
15. Total Revenue Requirements	7.77	7.61	0.17	6.98	7.61	(0.63)	8.33	7.61	0.72

* 7.5% x Difference Between Muni and PG&E SF Rate Base.

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Table 4-2
Comparative Cost Per kWh
For the Year 2011
Municipalization versus PG&E

	Base Case Transfer Price - RCNLD - SL Cents per kWh			Low Cost Case Transfer Price - Net Income Value Cents per kWh			High Cost Case Transfer Price - RCNLD - SF Cents per kWh		
Cost of Service	Municipal Costs	PG&E Costs	Difference	Municipal Costs	PG&E Costs	Difference	Municipal Costs	PG&E Costs	Difference
1. Power, Transmission & CTC	5.16	5.16	0.00	5.16	5.16	0.00	5.16	5.16	0.00
2. Distribution O&M Expense	0.59	0.67	(0.08)	0.59	0.67	(0.08)	0.59	0.67	(0.08)
3. Franchise Fees & Property Tax	0.17	0.17	0.00	0.17	0.17	0.00	0.17	0.17	0.00
4. Customer Accounts Expense	0.38	0.38	0.00	0.38	0.38	0.00	0.38	0.38	0.00
5. Customer Serv. & Info. Expense	0.32	0.32	0.00	0.32	0.32	0.00	0.32	0.32	0.00
6. Administrative and General Expense	0.22	0.23	(0.01)	0.22	0.23	(0.01)	0.22	0.23	(0.01)
7. SF 230 kv Cable O&M	0.02	0.00	0.02	0.02	0.00	0.02	0.02	0.00	0.02
8. Total Non-Energy Operating Costs	1.69	1.77	(0.07)	1.69	1.77	(0.07)	1.69	1.77	(0.07)
9. Depreciation - Plant and Equipment	1.01	0.71	0.30	0.70	0.71	(0.01)	1.23	0.71	0.52
10. Amort. of Development Costs	0.02	0.00	0.02	0.02	0.00	0.02	0.02	0.00	0.02
11. Cost of Capital on Basis Difference*	0.15	0.00	0.15	(0.08)	0.00	(0.08)	0.32	0.00	0.32
12. Subtotal	1.19	0.71	0.48	0.65	0.71	(0.06)	1.57	0.71	0.86
13. Cost of Captial on PG&E SF Rate Base	0.95	1.20	(0.25)	0.95	1.20	(0.25)	0.95	1.20	(0.25)
14. Income Taxes, State and Federal	0.00	0.53	(0.53)	0.00	0.53	(0.53)	0.00	0.53	(0.53)
15. Total Revenue Requirements	9.00	9.37	(0.37)	8.45	9.37	(0.91)	9.38	9.37	0.01

* 7.5% x Difference Between Muni and PG&E SF Rate Base.

As noted in previous chapters, this item and its financing comprise such a large fraction of the differences (as a result of the third and fourth items in this list) and its range of uncertainty is so wide that it determines the outcome of the total-rates-based analysis.

2. The total-rates disadvantage that municipalization likely has, relative to continued IOU service, as a result of the condemnation valuation, is offset (only partially or more than completely, depending on the amount of the valuation) by the lower muni gross cost of capital (freedom from income taxes, coupled with complete debt financing -- i.e., no equity).
3. An item that was important before California's recent electric-industry restructuring -- energy-supply costs, including stranded costs -- remains dominant in the total costs and rates picture for electric utilities and their customers, but it now is not affected at all by the muni/IOU choice, as discussed in chapter 3. Because it is dominant in determining the total utility costs and rates, comprising well over half of the total costs in all events, and because its levels will not be changed by municipalization, it is impossible for municipalization to make other than small-to-modest differences in total costs and rates.
4. All other cost factors, taken together, are too small to make a significant difference in overall muni/IOU total rates -- and the values used in our three cases are realistic optimistic assumptions, and thus systematically favor municipalization.

As discussed in section 4.A, simple total-rates comparisons misrepresent the true economic differences between the muni and BAU alternatives. Pure rate comparisons distort the picture because they fail to account for the fact, explained in that section, that what IOU ratepayers are buying under regulated tariffs is different from what muni ratepayer/owners purchase via their bills. Table 4-3 on the next page summarizes the differences between the pure total-rates comparison and the true economic analysis of the two options, and it presents the results of both approaches. Examining components of the rates reveals that there are two items on which the rate differences for the two scenarios are more apparent than real, one artificially favoring municipalization and a larger one artificially opposing it. Thus, when the artificial effects of these two components on the economic comparison are canceled by zeroing out these two rate-component differentials in Table

4-3, the true economic comparison is more favorable to municipalization than is suggested by the total rates comparison. In section 4.A, we explain these two items and related considerations.

Table 4-3: Economic Analysis of San Francisco's Electric-System Choice: Muni versus IOU/BAU (%NPV/LR – Incorporating Restructuring Effects)

Cost/Rates Element	*PG&E Total Rates Component*	*CCSF Rates Changes Base/Low/High Cases*	*CCSF Real-Effect Economic Change*
Energy Supply, Including CTC & Transmission	55.3%	0.0%	0.0%
Distribution Operations, Customer Costs & Overhead	18.7%	-0.8%	-0.8%
PG&E Distribution Ownership Costs //	20.4%		
CCSF Profit Elimination Savings		-2.6%	0.0%
SF Distribution System Acquisition Valuation Premium	0.0%	+5.9% / -0.4% / +10.3%	0.0%
Federal & State Income Taxes	5.6%	-5.6%	-5.6%
Total	*100.0%*	*-3.1% / -9.4% / +1.3%*	*-6.4%*
Contingency Cases:			
CCSF Reliability, etc. "De-averaging"	0.0%	+3.0%	+3.0%
CCSF Avoids CTC "Tail"	0.0%	-1.0%	-1.0%
Total with Both Contingencies	100.0%	-1.1% / -7.4% / +3.3%	-4.4%

In sum as a result of these two items and related considerations, the true economic comparison between the two options should be restated as follows. Savings to San Franciscans are more likely than not, and we find that they would be between 5% and 10%, as compared to PG&E service. A close second most likely is that savings would lie in the 0% to 5% range; this probability is increased by the possibility of the reliability-related rate de-averaging discussed in section 4.A. Third and fourth most likely -- both highly unlikely -- are that, respectively, municipalization would yield savings above 10% of the BAU costs to San Franciscans and the possibility that higher costs would result for San Franciscans from municipalization. Note again, as stated for the rates comparisons, that CCSF would own the SF electric-distribution system, and these net effects include paying for its acquisition.

Section 4.A shows that the real economic savings are almost completely due to a single factor: the avoidance of state and federal income taxes by munis, while IOUs must pay them and thus must be compensated for them in their regulated rates. This item favors the muni option by 5.6%. Another factor that adds a very small benefit, 0.8%, to municipalization for SF is that operating and maintenance costs for the SF electric distribution system are lower than the averages on PG&E's system, and San Franciscans would escape paying the differential (for IOU rates are based on system-average costs) by electing the muni option. To decide whether municipalization is preferable to IOU ownership (BAU), these expected-value economic results -- i.e., expected net real economic savings of 6.4% -- must be weighed against five other risk factors that attend the transition from IOU ownership to muni ownership. Two of these factors are amenable to quantification, and thus they appear as the contingency cases in Table 4-3: reliability-services "de-averaging" and avoidance of the CTC "tail". The former adds 3% to the muni costs, while the latter reduces them by 1%. The other three factors are acquisition-cost uncertainty (mis-valuation at trial), systematic efficiency differences (if any) between munis and monopoly-franchised/state-regulated IOUs, and possible job losses in SF due to PG&E moving its corporate offices out of SF in response to municipalization.

Besides highlighting the direct costs to San Franciscans in the rates they will pay for electric-utility service in the muni and BAU scenarios, the scope of work also requires us to address other

specific cost and benefit items. We do so in section 4.B, which shows first that San Franciscans will be little affected by the losses from property taxes and franchise fees (taxes on utility bill amounts), even though CCSF itself will be affected by this item. For San Franciscans, this issue is really a matter of moving the funds from one of their ratepayers/taxpayers/service-users' pockets to another, not a matter of getting a smaller pie. However, the effect on jobs in SF could be substantial: if PG&E (one of SF's largest employers) were to move its corporate offices to another city in response to SF electric municipalization, thousands of jobs would be lost to SF. At this time, we are also unable to discern any material effects of municipalization efforts on renegotiation of transmission and related contracts between CCSF and PG&E, because the restructuring and reregulation of the electric-utility industry in California seems to assure that CCSF will be able in either scenario to secure such service in reasonable terms. Working capital and initial inventory requirements, two other considerations raised in the scope of work, are very modest and make no difference to our bottom-line estimates.

Section 4.B also addresses the issue of decision guidelines, concluding mainly that NPV is the best tool for assessing total-rate differences which vary from year to year. NPVs, payback periods and internal rates of return (IRRs) of the options tell more or less the same story for rates: the savings appear to be small unless one can count on getting a valuation as low as the income-based valuation in the low-cost case. In sum, valuation and muni avoidance of income taxes are the issues from a rates perspective. The latter is a certainty, but the former involves great uncertainty, so the next step, based on this perspective, would be a more extensive and intensive RCNLD valuation study.

The results from the economic analysis, however, show that the differences between the two options are systematic and nearly constant (in percentage terms) from the start -- obviating the need for NPV, payback-period and IRR analyses. Moreover, the differences are larger than apparent in the total-rates comparison and due to a near certainty: continued income-taxation of IOUs and exemption from it for munis. The decision criterion here is simply a matter of determining whether the muni savings at least offset the risks incurred in getting them. Since one risk is the possibility that the condemnation process will err in the valuation and compensation CCSF must pay if it elects this route, and since that is the only risk about which CCSF can do anything at this time, further action

by CCSF on this matter might focus on that issue, if one takes the economic view, but making the valuation more precise is not important from this perspective to deciding whether to municipalize.

Nonetheless, condemnation valuation is, sooner or later, important for both the total-rates and economic approaches to the decision, if CCSF opts for the takeover, and our base case shows a net positive value from both viewpoints for municipalization. Hence, if The City is inclined to pursue municipalization and if it can spare dollars from other needs, we recommend a more extensive condemnation valuation study, focusing on RCNLD. In any event, this study provides an adequate basis for a policy decision on municipalization.

Finally, sections 4.A and 4.B, together with chapter 5, show that, to decide whether municipalization is preferable to IOU ownership (BAU), our expected-value economic results -- i.e., expected net real economic savings of 6.4% -- must be weighed against the two electric-industry restructuring contingencies (shown at bottom of Table 4-3), and three other risk factors that attend the transition from IOU ownership to muni ownership. Those risk factors include acquisition-cost uncertainty (mis-valuation at trial), systematic efficiency differences (if any, as we doubt, per chapter 3) between munis and monopoly-franchised/state-regulated IOUs, and net SF job losses due to PG&E possibly moving its corporate offices from SF in response to municipalization.

A. *Results of the Analysis*

The summary electric rates results in Tables 4-1 and 4-2 are developed from the assumptions and estimates made in chapters 2 and 3 (summarized in Figure 4-1) via the cost tables, Tables 4-4 (base case), 4-5 (low-cost case) and 4-6 (high-cost case), which are included with comparable table 4-7 (OCLD) at the end of this chapter. In these detailed cost tables, for each of the first ten years of municipal operation and for each scenario (muni and BAU), the annual detailed costs of service and 30-year net-present-worth totals are computed and compared, based on the Figure 4-1 assumptions. The cost and rate figures in all tables in this chapter are presented in nominal dollars (i.e., then-current

amounts, such as 2006 costs in 2006 dollars), reflecting an assumed underlying general inflation rate of 2.5% (approximating the long-term trends of recent years, as well as being consistent with economists' mainstream forecasts and with the costs of capital used in this report for PG&E and CCSF). The factor costs shown in the cost tables at the end of the chapter correspond to the rate components in the rate tables at the beginning of the chapter, adn they were developed from the cost elements and other factor estimates specified in chapters 2 and 3 and summarized in the assumptions table. Table 4-3 was also developed from Tables 4-4, 4-5 and 4-6, with Table 4-8 showing the computation of the key amounts in the middle column ("CCSF Rate Changes") of Table 4-3.

1. Analysis of Muni/BAU Differences in the Cost Tables

In each of the cost tables (4-4, 4-5, 4-6 and 4-7) at the end of the chapter, the upper bank of figures shows the costs each year for the CCSF muni electric utility, the middle bank shows them for PG&E's SF service, and the lower bank displays ancillary figures that are used to develop those in the upper two banks, as well as in Table 4-8. The "Annual Revenue Requirement Difference -- Municipal versus PG&E" line is the amount by which muni service rates are less than or greater than those of PG&E service; most of the figures in this line of these tables are negative, meaning that in most years for most cases PG&E's rates are expected to exceed muni rates. The bulleted results listed for the three cases at page 4-3 are taken from the bottom lines and from the projection of these ten-year streams of results over 30 years for the inputs needed for the long-run net-present-value (NPV) analysis[1]. The progression of annual electric-rate savings to electric ratepayers discussed in those bulleted points are found by dividing each year's Annual Revenue Requirements Difference by the

[1]The NPV computations are based on a real discount rate of 10% (a nominal rate of 12.5% with 2.5% expected inflation), which reflects both a typical-utility-customer viewpoint (as shown by the empirical literature) and an efficient and equitable social rate of discount (the marginal social productivity of private investment, or social opportunity cost of capital, as revealed by portfolio returns on private investment). These viewpoints and this number have also been adopted by the U.S. Federal (District of Columbia) Circuit Court of Appeals and FERC in the highest known civil-court holding on the matter, which coincidently involved PG&E and Northern California municipal utilities and in which the lead author of this report was the sponsoring expert for the rate and its rationale. (*Northern California Power Agency v. F.E.R.C.*, 37 F.3d 1517, 1522 (D.C.Cir. 1994).) The discount rate is sometimes a controversial issue in such analyses, and as a result of the annual revenues in each scenario and case, it is central to the ultimate issues here if one posits a higher discount rate -- for then the base-case net long-term benefit turns into a net cost. Otherwise, within reasonable ranges, it makes no difference.

PG&E Total Revenue Requirement, to compute an annual percentage difference. Our long-run NPV results for the three cases are shown in Figure 4-2 at page 4-4 and discussed below.

Table 4-4 summarizes our results for the base case. It shows in the lower left corner of the table that the expected electric-rates savings due to municipalizing PG&E's electric-utility service in SF is a minor net savings through the first ten years on a net-present-value basis to SF's residents, businesses, other institutions and The City. However, as shown by the progress of figures in the bottom line, the savings (and thus this NPV of savings) are growing yearly, after starting out at positive differences in the first three years (which indicate that muni costs exceed BAU costs in those years), and the savings continue to increase, converging on a long-term savings rate of about 4%. The reason for the improvement with time is mainly that the amount by which the CCSF acquisition cost exceeds PG&E's rate base allocated to SF is being amortized and thus the basis difference to which the gross costs of capital apply is declining.

The main difference between present PG&E costs and future costs in the cost tables (and between present PG&E rates and the future rates in the rate tables) is that both the muni and BAU costs reflect large decreases due to the effects of electric-utility restructuring and reregulation. This result is apparent in the cost tables at the end of the chapter and in the two rate tables at its beginning, because our numbers are consistent with the 10% and 20% residential and general-service rate cuts mandated by AB 1890.[2] If expected reductions from this source fail to materialize in one scenario (BAU or muni), then they will very likely also fail to materialize in the other one. Thus, the utility-cost- and rate-table estimates are not greatly sensitive to any factors other than the valuation methodology for the SF electric-utility distribution system and ancillary facilities (reflected in the depreciation, amortization, interest, and return and income tax lines in the tables, and discussed further in subsection 4.A.2 below) -- and they are clearly sensitive to that variable (which valuation is $795-million in the base case). As discussed in chapters 3 and 6, except for munis' exemption from income taxes (addressed in this chapter), other factors may make some lesser differences, but the cost

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[2] We have also included the net book value (NBV) results in Table 4-7 at the end of this chapter.

and rate tables show that, even taken together, those other factors are not large enough to change the overall economic outcome of the muni/BAU comparison.

Tables 4-5 and 4-6 show comparable results for the low- and high-cost cases, respectively. The long-run NPV difference is about 9% in the low-cost case (based on the $505-million valuation) and it is -1% in the high cost-case (based on the $999-million valuation), meaning that under municipalization CCSF ratepayers could realistically pay either more or less than if PG&E continued to own the local electric-utility distribution system. As noted above, the key factor that causes the relative rates changes in the cases is the valuation of the SF electric-distribution system and related facilities. If a figure approaching OCLD could be assured in the condemnation valuation, a prospect about which we are very skeptical, then there are substantial rates economies in the municipalization option. On the other side, and just as unlikely, if PG&E were to prevail with RCNLD valuation substantially greater than the high-cost case, then there would be substantial rates dis-economies.

Much more likely, if the value were set by the base-case replacement-cost formula (RCLD-SL + GCV + PS, with a result of $795-million), then there would be a long-run 3% rates advantage. The realistic range of results lies between 9% savings, using the low-cost valuation (income capitalization at $505-million), and 1% extra costs, using the high cost valuation replacement-cost formula (RCLD-SF + GCV + PS -- i.e., using economic depreciation, resulting in $999-million). The main reason that the rates savings are only modest relative to the total electric-service cost is that the energy-supply cost element, which (as we noted in chapter 3) is not affected by the muni/BAU choice, comprises more than half of the total rates. Hence, the total cannot be much swayed by municipalization. This result is further assured by the fact that, in most of the range of these three cases, 16% to 20% of the total cost is comprised of non-energy-supply costs that are not affected by the valuation method -- such as customer accounting and billing, distribution-system operations and maintenance, etc. Our cost tables show that we have estimated these costs for the muni scenario consistently below their levels in the BAU scenarios. However, these non-valuation/non-energy-supply costs are a small part of the total and cannot be moved across the wide percentage ranges that the valuation-related costs can (i.e., they are less uncertain), and thus these costs, like the energy-supply costs, keep the total rate

levels stable. In sum, because roughly three-quarters of the total rates are subject only to very minor variation, even assuming changes in these non-valuation costs that favor the muni option, the fact that valuation affects less than one-quarter of the total electric-service rates means that, inherently, municipalization will move total electric rates only slightly or moderately.

Considering the realistic range to be determined in litigation and which is justified by economic analysis, we assign comparable probabilities to the low-cost and high-cost cases, consistent with our discussion of this issue at the end of section 2.A. And we assign to the base case a significantly higher probability than for either the low-cost or high-cost case. Thus, in sum, the expected value is a rates savings of 3%, and a case can be made that it may exceed that level somewhat -- but there is nearly as large a chance that it will be less and even in negative territory (higher rates), instead of a higher percentage rates saving. In terms of the ranges for these results specified in the statement of work scope for this project, we believe the most likely result is that rates savings would result from municipalization and that they would lie in the 0% to 5% range. This outcome is significantly more likely than any other, in our view. Second most likely is that net rates savings would fall in the 5% to 10% range, and third most likely is that there would be increased rates in the 0% to 10% range, instead of savings. We see no realistic chance the savings in rates would exceed 10% and even less likelihood that the possible extra rates costs of municipalization, if it turned out to be more costly than BAU, would exceed 10% of the rates from PG&E. These figures and the others in this chapter include all costs that will be paid by ratepayers through their electric bills and particularly CCSF's costs to become the owner of the SF electric-distribution system.

2. Analysis of Muni/BAU Differences in Rate Tables

In this section, we delve further into the reasons for the differences in the electric-rates comparison of the muni and BAU scenarios -- here, as seen through rates and presented in Tables 4-1 and 4-2 at the beginning of the chapter. These two tables show the rates for the muni and BAU scenarios in 2002 (the first year of municipalization, in Table 4-1) and 2011 (representative of long-run outcomes, in Table 4-2) for all three realistic scenarios. The figures, computed directly from

those in the cost tables at the end of the chapter (which were developed from the assumptions and estimates specified in chapters 2 and 3 and summarized in Figure 4-1), divide into five sets:

- ***Energy supply costs:*** the "Power, Transmission & CTC" costs in line 1.

- ***Non-energy/non-valuation costs:*** lines 2 ("Distribution O&M expenses"), 3 ("Franchise Fees & Property Tax"), 4 ("Customer Accounts Expense"), 5 ("Customer Serv.& Info. Expense"), 6 ("Administrative and General Expense") and 7 ("SF Transmission O&M") -- all summed in line 8 ("Total Non-Energy Operating Costs").

- ***Valuation-based Costs:*** lines 9 ("Depreciation - Plant and Equipment"), 10 ("Amortization of Development Costs") and 11 ("Cost of Capital on Basis Difference") -- all summed in line 12 ("Basis Difference Subtotal").

- ***Net Costs of Capital on Present Rate Base:*** line 13 ("Cost of Capital on PG&E's SF Allocated Rate Base").

- ***Income Taxes:*** line 14 ("Income Taxes, State and Federal").

The figures in the tables are shown in cents per kilowatt-hour (c/kwhr) in the year in dollars of the year in which the figure is given (or "nominal" or inflated dollars -- i.e., 2002 dollars in year 2002).

The energy-supply costs include not only the costs of generating or purchasing energy directly, but also the stranded (CTC) costs that AB 1890 requires be passed on to SF electric users, regardless of municipalization; and the transmission costs to get electricity to the SF distribution grid network. Each of these elements and their totals are the same in a given year for all cases and both scenarios, as discussed in chapter 3, and in total they dominate the total electricity rates and costs, as discussed above and as seen by comparing their levels to the bottom-line total rate levels. They rise from one year to the next due to inflation (while customer growth, which also causes the figures

in the cost tables to increase, has no effect on the c/kwhr rates). Hence, they are 4.13 c/kwhr in 2002, and in all years there is no basis for any difference in them.

The non-energy/non-valuation costs include all the operations and maintenance costs of a muni electric utility (muni scenario) or of SF's share of PG&E's distribution operations (BAU scenario). They include none of the energy-supply costs and none of the costs associated with valuation or other capital costs that are affected by the gross-cost-of-capital difference between the muni and BAU options (i.e., also none of the muni's benefit by being free from income taxes and not having to generate equity earnings for stockholders). These six cost elements are the costs of the hundreds of people that PG&E now employs and which CCSF will employ to serve the same functions if it municipalizes the electric service. As noted above and as seen in the tables by comparing their levels to the total rate levels in the bottom line of each of the two rate tables, even taken collectively, these costs are only about 16% - 20% of the total. They vary from year to year for the same reason as the energy-supply rate elements: general inflation increases all of them slowly when they are expressed in nominal terms (and because customer growth, which also increases the total costs somewhat, does not increase the per-kwhr rates, for the cost increases are exactly offset by the revenue increases due to customer growth). The differences in the muni and BAU scenarios are the same for the base and realistic-optimistic cases, as explained in chapter 3 and summarized in the bullet-points below. This muni/IOU cost difference is real and persistent (even growing slowly with time), but very small (0.8% of total rates).

- Distribution costs are lower for the muni scenario due to SF's urban character, versus the system-wide area-cost-averaged distribution costs the CPUC uses for PG&E's rates.
- The franchise-fee and property-tax rates are the same in each scenario.[3]

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[3]As discussed in chapter 3, currently SF residents pay in their electric rates to PG&E amounts that exactly offset the electric franchise fees PG&E pays to CCSF. With municipalization, ratepayers might escape this cost element in their electric bills, but in any case, CCSF would lose the revenue now paid by PG&E -- and thus CCSF would either have to raise other taxes, reduce public services, or both. Instead, we have assumed that CCSF charges electric rates that exactly cover the lost franchise fees from PG&E electric service; hence, there is no difference between the muni and BAU scenarios on this item. For property taxes, the analysis is parallel and our assumption is, again, that CCSF would set electric rates to generate income in exactly the amount lost from PG&E's previous property-tax payments on municipalized electric property. However, for property taxes, the amount paid by SF ratepayers is currently more than the amount paid by PG&E to CCSF,

- Customer costs are the same in each scenario.
- The administrative and general costs are lower for the muni scenario because the O&M costs (part of the basis for the A&G costs) are lower for the muni option.
- Operating costs for the SF transmission system now owned and operated by PG&E are currently spread over its entire customer base by the CPUC's policy of charging area-averaged rates, but they would be concentrated on SF ratepayers by municipalization, thus adding a small increment to muni costs over the BAU cost (which rounds to zero).

The valuation-based costs include all costs which are affected by the condemnation acquisition cost. These costs are proportional to the differences between the SF-allocated part of PG&E's distribution rate base and the valuation for muni acquisition in each case. They are nearly zero in the low-cost case, the largest single differential in the base case, and huge in the high-cost case. In all three cases, they decline with time as the basis differential is amortized toward zero, and in the long-term all three cases would thus converge to zero on this factor (i.e., have a common muni rate base). This is the reason for the improvement from year to year in the muni rates, relative to the BAU rates. However, as discussed in the next section, this valuation-based differential is very likely chimeric and should be given little or no weight.

The net costs of capital on present rate base show the effects of switching from IOU financing with a roughly equal mix of debt and stockholders' equity to full debt (or debt and ratepayer) financing. In more common terms, this is the full effect of "profits" or the fact that PG&E is "beholden" to its stockholders. While significant, the amount, which increases slowly as does PG&E's rate base, is really quite modest, and it does not vary among the three realistic cases. However, as discussed in the next section, this differential, too, is more apparent than real and should be given little or no weight.

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due to the area-cost averaging done by PG&E under CPUC ratemaking standards. Hence, there is a net benefit on this item to SF ratepayers in municipalization, because it allows them to escape this tax or subsidy payment to other PG&E ratepayers. Thus, the rate and cost tables show small benefits to the muni scenario in all cases due to this effect.

The income-tax costs show the phenomenon to which we have alluded previously: that the muni exemption from state and federal income taxes to which the IOU is subject is a major factor, over twice as large as the effect of IOU profits (or more than two-thirds the effect of the gross cost of capital differential). Moreover, because this item is constant across all cases and grows with the IOU rate base, while the acquisition differential declines, and because the equity-return premium is illusory while this item is real (as also discussed in the next section), in the long-run this is the overwhelming difference between the two options. In the very long run, this item accounts for about 88% of the real difference between the two options, with the O&M cost savings (also persistent and real) making up the other 12%. Put another way, this item is completely real, persistent and substantial, and should be given substantial weight as the factor to be compared against the various risk factors discussed later in this chapter and chapter 5.

In sum, nearly three-quarters of the rates are going to be little affected (reduced about 0.8%) by the muni/IOU choice. Hence, the ability of municipalization is inherently limited in raising or lowering San Franciscans' electric bills For the other quarter, two factors that determine it favor municipalization systematically (i.e., continuously) and significantly, but only one is real. A third factor opposes municipalization substantially on its face, but it declines with time and is also illusory from the start. Hence, one factor -- income tax avoidance -- is significant, persistent and real, and it favors municipalization more each year. The net rate impact will almost certainly be to increase rates in the early years and decrease them in later years. From this perspective, the municipalization question raises equity elements: Namely, where is the fairness balance between ratepayers for the next few years paying higher rates so that ratepayers thereafter can pay lower rates?

A final point should also be stressed here concerning the assumptions, rates and costs. We thoroughly explored the possibility of using tax-exempt financing for the muni acquisition. As discussed in chapter 2, it is simply not possible. If it were, then the gross-cost-of-capital difference favoring munis in the long run would be even greater, because the muni financing rate of about 7.5% would be lowered to about 6%. Because it is not possible, we have not shown a line item for it in our already busy tables. However, from these tables for the realistic cases, one can calculate that it

would make a difference of 1% to 2% in NPV, with the amount depending on the valuation: i.e., it would add less benefit to the cases with lower valuations that it would to those with higher valuations.

3. Economic Analysis of Muni/BAU Choice, per Table 4-3

By shifting our focus from valuations and total rates comparisons to the components of the rates, as indicated in the previous section, we may see better the true economics of the choice between the muni and BAU options. Examining components of the rates more closely, as we do in this section, reveals that there are two items on which the rate differences for the two scenarios are illusory differences, one artificially favoring municipalization and a larger one artificially opposing it. Thus, when the misleading differences in the two scenarios for these two components are canceled by zeroing out these two rate-component differentials, as we have done in Table 4-3, the economic comparison is more favorable to municipalization than is suggested by the total rates comparison. Below, we review these two items and related considerations.

The apparent difference artificially opposing municipalization is the rate differential based on the margin between SF's allocated share of PG&E's distribution "rate base" (on which PG&E's rates are based in the BAU scenario) and the valuation which the condemnation process will require CCSF to pay for PG&E's facilities (on which CCSF rates would be based in the muni scenario). The reason this difference is not real is the following: When PG&E owns the facilities (as it now does), its investors and customers in other areas share in various ways the true economic value of the SF facilities to the extent that such value differs from PG&E's allocated rate base; however, if CCSF owned the facilities (as it would under municipalization), the SF ratepayers would capture the facilities' entire economic value for their benefit, and they would not have to share any of it with PG&E stockholders or customers in other areas. Hence, assuming that the condemnation valuation set an acquisition price that exceeds PG&E's SF-allocated rate base and that (as discussed in chapter 2 and as we expect it to) the legal valuation reflects the real value, then the SF assets had appreciated value that was not reflected in PG&E rates at the time of the condemnation, and which would accrue

to PG&E's stockholders and non-SF ratepayers in the future. By acquiring those assets, SF's new ratepayer/taxpayer/owners would acquire the rights to such values as they are realized. (Such realization has happened in communications and other regulated sectors in recent years that have undergone restructuring and re-regulation. Also, if the assets' value were less than the SF-allocated rate base, then the legal valuation process would also pass this benefit on to CCSF to be realized in SF ratepayers' bills.) Put another way, the rates comparison is misleading because it fails to reflect the difference in what the rates are paying for, or what ratepayers are getting for their money. With an IOU or a muni, they get service today at the stated rate, but with muni ownership they also have additional claims on future economic value (which may be positive or negative) in addition. In other words, IOU customers are only ratepayers, while muni customers are ratepayer/owners. The effect of this chimeric difference in the rates comparisons here is to understate the value of municipalization by 5.9%, depending of course on the exact condemnation valuation amount -- i.e., the rates comparison artificially favors the IOU/BAU scenario by about 5.9%, all else being equal. Thus, correcting the comparison by removing this difference increases the apparent base-case attractiveness of the muni option by 5.9%. Finally on this point, note what was observed at great length at the end of section 2.A.3: APPA recognizes the appreciation value discussed here of such systems and the differences stated here between the roles of IOU ratepayer and muni ratepayer/owner.

The apparent, but not real difference on the other side of the ledger is the difference between San Franciscans paying through their rates a market rate of return on PG&E's equity investment (or, more commonly, its bookkeeping "profits"), as compared to paying the interest-rate cost of capital that CCSF would have to pay to finance the part of the SF system PG&E now finances with funds from stockholders. This rate differential reflects the fact that, in public-policy theory and under the law, regulated ratemaking for IOUs will not require their ratepayers to pay for imprudent or unreasonable investments and other contingencies, except through paying the difference between the IOU's equity cost of capital and the interest rate. Muni ownership, on the other hand, assures that they will pay costs of imprudence, unreasonableness and other contingencies associated with being the beneficial owners of the assets if and when such costs are actually incurred. In a very real sense, then, having PG&E own these assets and paying its stockholders through electric rates an equity

premium (above the interest rate) on their investment is akin to the ratepayers carrying insurance on assets and their management. Owning them through a muni, by contrast, is akin to buying no insurance and, instead, "self-insuring" (carrying those risks directly instead of pool-sharing them with others similarly situated). The self-insurance route is usually cheaper, but when things go wrong, as they did for the WPPSS muni utility owners,[4] the results are sometimes disastrous for the ratepayers. Economically, in the long run the two options are equivalent, depending on one's risk preferences,[5] and thus the rate differential based on this item is illusory. Like the previous item, this difference in rates is really just a manifestation of the difference in what the ratepayers are buying under the two systems with the rates they pay.[6] The effect of this difference is to overstate the value of municipalization by 2.6% -- i.e., the rates comparison artificially favors the muni scenario by this much, all else being equal. Correcting the comparison by removing this difference will increase the apparent attractiveness of the IOU/BAU option by 2.6%. Since this effect is smaller than the first one, correcting for both of them yields a net 3.3% improvement in the economics of the muni option.

In addition to these two adjustments, two contingency items can be quantified that bear upon the probabilities that the true cost comparison of the two options will fall into each of the four ranges specified for describing the results of our assessments (0% to 5%, etc.). One item is the possibility

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[4]WPPSS is the (State of) Washington Public Power Supply System, which began construction of five large nuclear projects and then abandoned billions of dollars of investment when the power turned out to be unneeded and extremely expensive. This led to the largest public-sector bond default in U.S. history, as well as to huge losses through increased electric bills for ratepayer/owners of public power authorities comprising WPPSS. Under IOU ownership, much of these costs would have been absorbed by the stockholders through write-offs and ratemaking cost disallowances. In some cases such disallowances have wiped out the entire equity cushion and put the IOU in bankruptcy.

[5] If the ratepayers' risk tolerances in this area exceed those of utility stock investors, then public ownership (ratepayer self-insurance) is better in their view, assuming that public ownership does not have any negative effects on management efficacy, as compared to franchised/regulated IOU ownership. If the ratepayers' risk tolerance is less than that of utility stock investors in this matter, then paying the IOU risk premium and avoiding the risks is better in their view, again assuming no adverse effects on management. If the ratepayers and utility stockholders have the same risk preferences in this area, then (assuming no difference in the two systems on the efficacy of management), they are indifferent between the muni and IOU/BAU options on this count.

[6]Thus, both of these factors involve only a change of position of SF ratepayers vis-a-vis ownership interests in the assets and their management and benefit/cost/risk incidents. In the first one, ratepayers pay a higher expected rate to get a higher expected benefit through public ownership; and in the second one they pay a lower expected rate by carrying through public ownership a risk that they now avoid by paying an equity risk premium (a form of insurance).

that the AB 1890 reforms will lead to a ratemaking adjustment imposed on a CCSF muni that undoes another area-cost averaging factor from which San Franciscans benefit and over which CCSF and its ratepayer/owners would have no control. This factor is the energy-supply-system reliability support and ancillary services which are provided to the SF area by PG&E's transmission grid and PG&E's SF generating units. Due to SF's geographic isolation at the end of the San Francisco Peninsula, these services are more costly for SF than for the average location on the PG&E system. The Independent Energy Producers and California Cogeneration Council recently raised this unbundling possibility in a brief filed before the CPUC in Application Number 96-07-009, but since it is not certain to happen, and we have not included it in our "base case" estimates here. However, it is a contingency that is reflected in our high-cost case (for municipalization), and our analyses show that realization of this risk due to municipalization would increase costs of the muni option by about 3%. As noted in an earlier chapter, in text-book policy analysis, this item (and, indeed, all area de-averaging proposals) should be decided without regard to anyone's municipalization, and thus it should not be attributed to the decision. In terms of political reality, though, a decision on it well may be precipitated by a large municipalization.

The second item is the possibility that a CCSF muni may escape the "tail" (post-2002 charges) of the CTC discussed in chapter 3. This possibility exists under AB 1890, as currently written, but it is too speculative to count on at this point. If realized, it would add nearly a 1% (0.95%) benefit to the muni option.

In sum, then, the true economic comparison between the two options should be restated as follows. Savings to San Franciscans are more likely than not, and we find that they would most likely be between 5% and 10%, as compared to PG&E service. A close second most likely is that savings would lie in the 0% to 5% range; this probability is increased by the possibility of the SF reliability-rate de-averaging just discussed. Third and fourth most likely -- both highly unlikely -- are that, respectively, municipalization would yield savings above 10% of the BAU costs to San Franciscans and that higher costs would result for San Franciscans from municipalization.

As discussed in the previous section and as shown in Table 4-3, the real economic savings are almost completely due to a single factor: munis do not pay state and federal income taxes, while IOUs must pay them and thus must be compensated for them in their regulated rates. This item favors the muni option by 5.6%. Another factor that adds a very small benefit (0.8%) to municipalization for SF is that non-energy operating costs for the SF electric distribution system are lower than the averages on PG&E's system. San Franciscans would escape paying that differential (for IOU rates are based on system-average costs) by electing the muni option. To decide whether municipalization is preferable to IOU ownership (BAU), these expected-value economic results -- i.e., expected net real economic savings of 6.4% -- must be weighed against the two contingency items and the three risk factors that attend the transition from IOU ownership to muni ownership. In the rest of this section, we address the first two risk factors, and the third one (PG&E possibly moving its headquarters) is discussed in section 4.B.2.

The first economic risk factor is the one that dominates the rates comparison: the acquisition cost uncertainty. As discussed in chapter 2, our analysis of the condemnation process is based on the assumption that the valuation may err either to the high or low side of the actual value, but that on average it will tend to the true value and not often be very wide of that mark. On the other hand, this view also means that the actual value will usually err by some amount and may occasionally err significantly. The error will have positive or negative consequences for San Franciscans, depending respectively on whether the valuation is low or high, relative to the true value. If the valuation is low, they thereby procure some immediate economic gain from municipalization in addition to the income-tax-avoidance and area-rate de-averaging gains of municipalization. This possible outcome, of course, favors municipalization to the extent of the valuation error. But, if the valuation exceeds the actual economic value, then the gains from avoiding income taxes and area-rate averaging will immediately be eroded and possibly eliminated. The salient observation about this risk is that it is random and little can be done about it -- save, of course, to present the strongest possible case in court if one elects the muni option.

The second risk factor is the possibility that one of the two options -- a muni controlled by direct public governance versus franchised (monopoly) IOU controlled by American utility regulation -- will be systematically operationally less efficient than the other, as discussed in section 3.B.3.[7] Based on substantial experience with both systems and knowing the absence of definitive research on this issue, we conclude that no one can say with certainty that either organizational approach is more efficient on average than the other.[8] Hence, given the lack of definitive evidence on either side, we have not incorporated this matter in any of our quantitative assessments, but have instead raised it only as a residual unquantifiable uncertainty which is important to the ultimate decision.

B. Other Economic & Public Policy Issues Affecting Municipalization

1. Non-Income Taxes

Municipalizing electric-utility service in SF will cause CCSF to lose revenues from electric-utility franchise fees (utility-users' taxes), property taxes and payroll taxes paid by PG&E. We estimate that these total very roughly $10.7-million/year in 1996, with $2.4-million for franchise fees

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[7] Operational efficiency -- including all matters from day-to-day operations to long-term planning and resource allocation -- is the issue here, because other efficiency factors that would change costs to ratepayers (such as differing muni and IOU net and gross costs of capital, and economies of scope and scale) have already been treated elsewhere. Also, this point addresses the systematic aspects of industrial organization -- i.e., Which system generally functions more efficiently? -- not the random chance that SF will wind up with management under either system that is abnormally good or poor relative to PG&E's. The random chance of good or poor management is, of course, always present under either option, but nothing can be done in making the choice between the two options to mitigate the uncertainties or improve the expected results under either method. Hence, the key question that can be addressed as bearing on this choice is whether one approach is systematically more or less efficient -- and that is what we address and the matter on which future discussion should focus.

[8] The question here is not: Which is more efficient on average, the public or private sector? The question is a comparison of municipalization (classic socialization) of electric service with the U.S. alternative of monopoly franchise and state regulation. The reason for that choice is that sectors such as electric distribution are not yet amenable to competitive provision by the private sector. In the argot of public policy analysis, the starting point here is that there is a "market failure" -- namely, this sector is a "natural monopoly", and thus there is no purely competitive-market alternative. Thus, the question is: Which works more efficiently (or, more generally, "better", however defined), direct political control of the operation or political control of a private provider which owns and runs the operation? It is on this question that there is no definitive analysis or evidence, only a range of experience on both sides.

(0.5% of gross electric revenues of about $480-million), $3.8-million for property taxes (1% of assessment of about $376-million) and $4.5-million for payroll taxes (escalated from 1988 University of California study).[9] However, in terms of a social-cost analysis or the net effect on the people and businesses of SF, all of it is mostly a "wash," as discussed in the previous section. Hence, if the SF ratepayers pay these revenues to PG&E, which then pays them to The City, then ratepayers will be spared these costs in their other roles as taxpayers and users of public services; if they do not pay them in their utility bills, then they will pay them in some combination of increased other taxes and reduced services. Thus, from the viewpoint of the residents and businesses of SF, as well as for CCSF as a governmental unit, these items are a matter of being taken out of one collective pocket and put into another. These dislocations may raise what economists and policy analysts call incidence effects (Who benefits and who pays?), but that is beyond the scope of this study, and they do not raise economic efficiency or net social benefit questions as they arise here. The APPA paper, "Straight Answers to False Charges Against Public Power", at page 13, also makes the point that there is no net loss of benefit from taxes paid by IOUs when a community municipalizes its electric system.

2. Jobs

A more important effect would be due to one of the assumptions made in making the payroll-tax loss estimate (which loss we do not include in our economic comparisons of the two options): that, if SF were to municipalize PG&E's electric service, a likely response by PG&E would be to move its central offices out of The City, in addition to reducing its local-office staff. A PG&E central-office move would mean the loss of thousands of jobs from (one of) the largest employer(s) in SF; this job loss would be a net loss, even after accounting for the hundreds of electric-distribution and other local-service jobs that would move from PG&E to CCSF. While there is no certainty that PG&E would take this action, the initial cost to PG&E may well be recouped by lower rent and related costs over a reasonable time.

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[9] We attempted to get this data directly from the CCSF, but we were informed by CCSF officials we contacted that under CCSF Rev./Bus. Reg's Section 1023 ("Disclosure of Business of taxpayers, etc.") that it is a violation of this CCSF ordinance for the Tax Collector to disclose this data.

3. PG&E/HHWP Transmission Contract and Services

The RFQ states that municipalization would further alter The City's relationship with PG&E, noting that PG&E currently provides a full range of transmission, reliability and ancillary services to HHWP.[10] Before the electric-utility industry restructuring and reregulation of the last year, this may have been a problem, but the AB 1890 provisions appear to obviate the problem now and in the future, because it requires transmission operators to provide them on a fair and not unduly discriminatory basis, and that the services be priced at economically efficient and equitable levels. Hence, we do not see any basis for concluding that municipalization will raise any problems for renegotiation that would not otherwise arise.

4. Working-Capital and Initial-Inventory Requirements

The amount of working capital an enterprise requires depends on a number of factors, especially its billing and purchasing practices. If purchases are made on credit, or customers' payments are required in advance of the receipt of goods and services, working-capital requirements may be minimal. However, if payment for supplies must be made in advance, business is seasonal or customers are billed periodically in arrears, then working-capital requirements may be substantial. While elaborate "lead/lag" studies are often performed to establish working-capital requirements in rate cases for regulated utilities, a widely used rule of thumb is that working-capital requirements of one-twelfth (1/12) of annual billings is appropriate for electric utilities. In our forecast for the year 2002, we estimate that annual operating costs for the municipal utility will be approximately $244-million. Thus, the expected working capital level will be about $20.3-million at the time of start-up of retail electric-utility service by HHWP. This cost is not included in either the BAU or municipalization scenarios, but both operations would require comparable levels of working capital (with PG&E's requirements slightly lower due to scale economies, but its financing cost being

[10] Services include transmission and distribution of HHWP energy, emergency and maintenance power, supplemental power, capacity reserves and spinning reserves.

somewhat higher, although not as high as its overall cost of capital), and thus the comparative figures are not much skewed by it. To correct the figures in 2002 for this factor, one could add about 0.04 c/kwhr to each.

The T&D maintenance function requires that the utility have on hand sufficient spare parts to respond quickly to customer-service requirements. The inventory will generally require numerous small items and a few major items. We estimate that approximately one percent of the original cost of the distribution-system cost is adequate. We base this conclusion on a review of the distribution-related inventory of materials and spare parts for PG&E in comparison to its distribution plant's original cost. The underlying data were taken from PG&E's annual reports to FERC for the last five years. Since the estimated original cost of the SF distribution system in 2002 is approximately $600-million, the expected required allowance for initial inventories is $6-million. The carrying cost of this item, at an interest rate of 7.5% per annum, would be about $0.45-million, or less than 0.01 c/kwhr -- i.e., this additional increment to the municipalization cost is perhaps lost in the rounding, even when the figures are computed to the two-decimal-place level needed here to sharpen the differences between the two scenarios. If The City proceeds with municipalization in this matter, it should address this item in the process, but it is de minimis to the overall decision.

5. Decision Guidelines

The work-scope statement in the RFQ states that the this report should incorporate our findings and recommendations in the context of standard decision guidelines for investments, such as expected internal rate of return (IRR), payback and NPV. Our primary results have been stated in NPV terms from the viewpoint of ratepayers, taxpayers and society as a whole in SF, and they are illustrated in typical future rates and costs for the two scenarios, expressed at future price levels. We believe these figures are the most understandable and critical among the various decision guidelines, and they answer the basic question guiding this project: namely, to determine which of four ranges the relative cost changes fall into as a result of the decision.

As a further reference point in the base case, the payback period for rates is in the neighborhood of a few decades -- i.e., well beyond the range of any meaningful estimates. (Our detailed estimates run a reasonable ten years, which shows the primary effects and provides the great bulk of the two scenarios' NPVs and most of the effect of their differences, which are essentially unchanging on a percentage basis after the first few years.) In view of the NPV difference of 3%, the effective IRR is about 13% in nominal terms or more than 10% in real terms. In the low-cost case, the payback is about 15 years and the IRR is somewhat higher, depending on values beyond the range of our forecast period. In the high-cost case, of course, payback is never reached, and the IRR is significantly negative, with the specific (irrelevant) rate requiring projections beyond the range of our forecast period.

The results from the economic analysis, however, show that the differences between the two options are systematic and nearly constant (in percentage terms) from the start -- obviating the need for NPV, payback-period and IRR analyses. Moreover, the differences are larger than apparent in the total-rates comparison and due to a near certainty: continued income-taxation of IOUs and exemption from it for munis. The decision criterion here is simply a matter of determining whether the muni savings at least offset the various risks incurred in getting them.

6. Sensitivity Analysis - What if

In addition to the acquisition cost or condemnation value, income taxes and equity-return premium, there are only two cost variables that could materially affect the economic results reported in this chapter: O&M and reliability costs. What if O&M costs for the SF municipal electric utility are the same as those forecasted for PG&E, and what if municipalization triggers the allocation of SF reliability costs (SFOC costs) directly to SF electric ratepayers?

We analyzed these possibilities by creating two "what if" scenarios for all five cases. In the "what if" scenario where O&M costs are not lower, but instead are the same as PG&E's O&M costs,

the approximate impact on each of the 5 cases was an increase in the cost or a reduction in the benefits of municipalization, of 0.8% over 30 years, depending on the case. In the "what if" scenario where we assumed that municipalization would trigger the direct allocation of SF reliability cost to SF electric ratepayers, the average impact was a reduction in the benefits or increase in the cost of municipalization of 3%.

For example, in the base case we calculated a net present value savings over a 30-year operating period of approximately 3%. If O&M costs for the muni are the same as PG&E's O&M costs, this 3% net benefit is reduced to approximately 2%. If municipalization triggers the direct allocation of SF reliability costs to SF ratepayers, the net present value savings in the base case over a 30-year operating period is reduced from 3% down to zero.

Clearly, given its material negative impact on the costs and benefits of municipalization, the issue of SF reliability must be tracked as the rules and regulations for open market competition evolve over the next one to two years, and a definitive assessment of the impact made and incorporated in any future municipalization action.

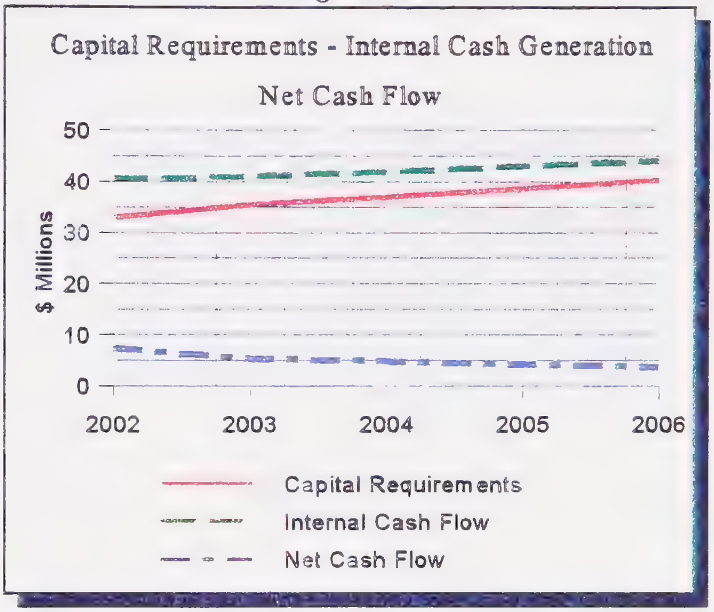
7. Ongoing Capital Requirements, Internal Cash Flow and Financing

As part of this assignment, we were asked to present an analysis of the ongoing capital requirements, internal cash generation and external financing for the SF municipal electric utility after the start of operations. The SF municipal electric utility will be required to finance plant and equipment replacements, capital additions and changes in working capital requirements, and to fund the retirement of bonds issued to acquire the SF distribution system from PG&E, initial working capital requirements and inventories, and development and litigation costs -- i.e, total capital requirements.

The primary source of funds to finance annual capital requirements are internally generated fund from operations. Depreciation expense, which represents the recovery of sunk capital costs, will

produce the greatest portion of internal funds. Figure 4-3, below, contains our forecast of the total annual capital requirements, internal cash flow for the base-case and for the first five years of operations, 2002 through 2006.

Figure 4-3



Capital requirements are primarily: 1) capital additions and replacements of distribution plant and equipment; 2) bond retirements[11]; and 3) working capital requirements. Internal cash generation is the annual net internally generated funds from electric utility operations and is produced by the inclusion of non-cash expenses such as depreciation in the cost of service. As Figure 4-3 shows, annual capital requirements and internal cash generation increase at about the rate of inflation (2.5%). We performed the same analysis for both the low-cost case and the high-cost case, and determined that the results were approximately about the same.

[11]In forecasting annual capital requirements for the municipal electric utility, we have assumed that debt principal payments will be based on a "mortgage" type payment. However, other options, such as a fixed-term loan, where the entire principal is retired at a fixed future date via the issuance of refunding bonds, are also financing options.

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Table 4-4
Estimate of Revenue Requirements 2002 - 2011
Municipal Versus PG&E - Base Case
Transfer Price RCNLD - Straight Line Depreciation

Municipal Costs	Net Present Value @12.5% 30 Yr NPV	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Distribution O&M Expense	$206,596,136	$21,050,932	$21,694,380	$22,356,197	$23,037,547	$23,738,992	$24,461,110	$25,204,497	$25,969,766	$26,757,545	$27,568,482
System Power, Transmission & CTC	1,834,457,174	183,431,000	190,537,000	197,695,000	204,876,000	212,076,000	216,912,000	219,042,000	226,694,000	234,377,000	242,091,000
Franchise Fees and Property Tax	61,355,007	6,489,409	6,672,675	6,857,131	7,042,695	7,229,391	7,405,371	7,568,977	7,761,409	7,955,273	8,155,515
Customer Accounts Expense	132,646,579	13,515,873	13,929,002	14,353,926	14,791,930	15,241,757	15,705,397	16,182,693	16,674,038	17,179,837	17,700,503
Customer Service & Info Expense	111,547,920	11,366,078	11,713,496	12,070,832	12,438,715	12,817,448	13,207,343	13,608,721	14,021,915	14,447,262	14,885,113
Administrative and General Expense	76,634,408	7,808,590	8,047,269	8,292,762	8,545,593	8,805,693	9,073,555	9,349,305	9,633,172	9,925,389	10,226,197
SF 230 kv Cable O&M	6,451,001	687,194	704,374	721,983	740,033	758,534	777,497	796,934	816,858	837,279	858,211
Total Operating Costs	2,429,688,224	244,349,076	253,298,196	262,347,831	271,472,512	280,667,815	287,542,272	291,753,127	301,571,158	311,479,586	321,485,021
Depreciation - Plant and Equipment	348,366,411	39,412,215	39,897,605	40,894,098	41,921,677	42,987,939	44,094,378	44,963,030	45,774,183	46,618,174	47,494,698
Amort. of Capitalzed Development Costs	8,327,556	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000
Interest on Debt	426,086,050	60,389,173	59,419,060	58,451,822	57,488,102	56,528,091	55,571,990	54,640,975	53,742,831	52,878,706	52,049,913
Total Revenue Requirements	$3,212,468,241	$345,300,464	$353,764,861	$362,843,751	$372,032,291	$381,333,845	$388,358,640	$392,507,132	$402,238,172	$412,126,466	$422,179,632
PG&E Costs											
Distribution O&M Expense	234,482,336	$23,892,372	$24,622,672	$25,373,821	$26,147,139	$26,943,264	$27,762,853	$28,606,583	$29,475,146	$30,369,259	$31,289,656
System Power, Transmission & CTC	1,834,457,174	183,431,000	190,537,000	197,695,000	204,876,000	212,076,000	216,912,000	219,042,000	226,694,000	234,377,000	242,091,000
Franchise Fees and Property Tax	61,355,007	6,489,409	6,672,675	6,857,131	7,042,695	7,229,391	7,405,371	7,568,977	7,761,409	7,955,273	8,155,515
Customer Accounts Expense	132,646,579	13,515,873	13,929,002	14,353,926	14,791,930	15,241,757	15,705,397	16,182,693	16,674,038	17,179,837	17,700,503
Customer Service & Info Expense	111,547,920	11,366,078	11,713,496	12,070,832	12,438,715	12,817,448	13,207,343	13,608,721	14,021,915	14,447,262	14,885,113
Administrative and General Expense	81,375,062	8,291,635	8,545,079	8,805,758	9,074,223	9,350,420	9,634,851	9,927,659	10,229,087	10,539,381	10,858,796
Total Operating Costs	2,455,864,078	246,986,367	256,019,924	265,156,468	274,370,702	283,658,280	290,627,815	294,936,633	304,855,595	314,868,012	324,980,583
Depreciation	249,830,598	25,609,351	26,482,476	27,375,319	28,288,346	29,222,036	30,176,878	31,153,375	32,152,043	33,173,410	33,365,707
Return and Income Tax	609,236,951	65,297,381	67,001,670	68,713,327	70,432,887	72,160,907	73,897,959	75,644,635	77,401,544	79,169,317	81,064,346
Total Revenue Requirements	$3,314,931,628	$337,893,099	$349,504,071	$361,245,114	$373,091,936	$385,041,223	$394,702,651	$401,734,643	$414,409,182	$427,210,739	$439,410,636
Annual Revenue Requirement Difference Municipal versus PG&E	($102,463,387)	$7,407,365	$4,260,790	$1,598,636	($1,059,645)	($3,707,378)	($6,344,011)	($9,227,511)	($12,171,010)	($15,084,274)	($17,231,005)
% Change In NPV From PG&E 30 Yrs	-3.09%										
Base Case Analysis		2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
RCNLD NBV		$782,188,971	$770,404,131	$758,657,621	$746,958,020	$735,307,877	$723,709,870	$712,446,336	$701,621,083	$691,249,414	$681,348,844
RCNLD Annual Depr & Amort		39,412,215	39,897,605	40,894,098	41,921,677	42,987,939	44,094,378	44,963,030	45,774,183	46,618,174	47,494,698
PG&E Net Book Value - SF Distribution		480,834,911	493,384,907	505,989,151	518,651,599	531,376,340	544,167,592	557,029,711	569,967,189	582,984,663	596,939,220
PG&E Annual Depr		25,609,351	26,482,476	27,375,319	28,288,346	29,222,036	30,176,878	31,153,375	32,152,043	33,173,410	33,365,707
PG&E NBV Return @ 7.5%	$336,471,070	36,062,618	37,003,868	37,949,186	38,898,870	39,853,225	40,812,569	41,777,228	42,747,539	43,723,850	44,770,442
PG&E NBV Return @ 9.45%	$423,953,549	45,438,899	46,624,874	47,815,975	49,012,576	50,215,064	51,423,837	52,639,308	53,861,899	55,092,051	56,410,756
PG&E Federal and State Inc Tax	$185,283,403	19,858,482	20,376,797	20,897,352	21,420,311	21,945,843	22,474,122	23,005,327	23,539,645	24,077,267	24,653,590

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Table 4-5
Estimate of Revenue Requirements 2002 - 2011
Municipal Versus PG&E - Low Cost Case
Transfer Price - Net Income Method

Municipal Costs	Net Present Value @12.5% 30 Yr NPV	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Distribution O&M Expense	$206,596,136	$21,050,932	$21,694,380	$22,356,197	$23,037,547	$23,738,992	$24,461,110	$25,204,497	$25,969,766	$26,757,545	$27,568,482
System Power, Transmission & CTC	1,834,457,174	183,431,000	190,537,000	197,695,000	204,876,000	212,076,000	216,912,000	219,042,000	226,694,000	234,377,000	242,091,000
Franchise Fees and Property Tax	61,355,007	6,489,409	6,672,675	6,857,131	7,042,695	7,229,391	7,405,371	7,568,977	7,761,409	7,955,273	8,155,515
Customer Accounts Expense	132,646,579	13,515,873	13,929,002	14,353,926	14,791,930	15,241,757	15,705,397	16,182,693	16,674,038	17,179,837	17,700,503
Customer Service & Info Expense	111,547,920	11,366,078	11,713,496	12,070,832	12,438,715	12,817,448	13,207,343	13,608,721	14,021,915	14,447,262	14,885,113
Administrative and General Expense	76,634,408	7,808,590	8,047,269	8,292,762	8,545,593	8,805,693	9,073,555	9,349,305	9,633,172	9,925,389	10,226,197
SF 230 kv Cable O&M	6,451,001	687,194	704,374	721,983	740,033	758,534	777,497	796,934	816,858	837,279	858,211
Total Operating Costs	2,429,688,224	244,349,076	253,298,196	262,347,831	271,472,512	280,667,815	287,542,272	291,753,127	301,571,158	311,479,586	321,485,021
Depreciation - Plant and Equipment	242,745,502	24,826,418	25,311,808	26,308,301	27,335,880	28,402,142	29,508,581	30,377,233	31,188,386	32,032,377	32,908,901
Amort. of Capitalzed Development Costs	8,327,556	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000
Interest on Debt	322,525,345	39,626,912	39,750,734	39,877,431	40,007,645	40,141,569	40,279,404	40,442,323	40,638,114	40,867,924	41,133,066
Total Revenue Requirements	$3,003,286,627	$309,952,407	$319,510,739	$329,683,563	$339,966,038	$350,361,527	$358,480,257	$363,722,683	$374,547,658	$385,529,886	$396,676,987
PG&E Costs											
Distribution O&M Expense	$234,482,336	$23,892,372	$24,622,672	$25,373,821	$26,147,139	$26,943,264	$27,762,853	$28,606,583	$29,475,146	$30,369,259	$31,289,656
System Power, Transmission & CTC	1,834,457,174	183,431,000	190,537,000	197,695,000	204,876,000	212,076,000	216,912,000	219,042,000	226,694,000	234,377,000	242,091,000
Franchise Fees and Property Tax	61,355,007	6,489,409	6,672,675	6,857,131	7,042,695	7,229,391	7,405,371	7,568,977	7,761,409	7,955,273	8,155,515
Customer Accounts Expense	132,646,579	13,515,873	13,929,002	14,353,926	14,791,930	15,241,757	15,705,397	16,182,693	16,674,038	17,179,837	17,700,503
Customer Service & Info Expense	111,547,920	11,366,078	11,713,496	12,070,832	12,438,715	12,817,448	13,207,343	13,608,721	14,021,915	14,447,262	14,885,113
	81,375,062	8,291,635	8,545,079	8,805,758	9,074,223	9,350,420	9,634,851	9,927,659	10,229,087	10,539,381	10,858,796
Total Operating Costs	2,455,864,078	246,986,367	256,019,924	265,156,468	274,370,702	283,658,280	290,627,815	294,936,633	304,855,595	314,868,012	324,980,583
Depreciation	249,830,598	25,609,351	26,482,476	27,375,319	28,288,346	29,222,036	30,176,878	31,153,375	32,152,043	33,173,410	33,365,707
Return and Income Tax	609,236,951	65,297,381	67,001,670	68,713,327	70,432,887	72,160,907	73,897,959	75,644,635	77,401,544	79,169,317	81,064,346
Total Revenue Requirements	$3,314,931,628	$337,893,099	$349,504,071	$361,245,114	$373,091,936	$385,041,223	$394,702,651	$401,734,643	$414,409,182	$427,210,739	$439,410,636
Annual Revenue Requirement Difference Municipal versus PG&E	($311,645,001)	($27,940,692)	($29,993,332)	($31,561,551)	($33,125,898)	($34,679,696)	($36,222,394)	($38,011,960)	($39,861,524)	($41,680,853)	($42,733,649)
% Change In NPV From PG&E 30 Yrs	-9.40%										

		2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Net Income Method NBV		$505,358,831	$508,159,788	$510,999,074	$513,885,271	$516,820,924	$519,808,714	$523,130,977	$526,891,521	$531,105,649	$535,790,875
Net Income Method Annual Depr & Amort		24,826,418	25,311,808	26,308,301	27,335,880	28,402,142	29,508,581	30,377,233	31,188,386	32,032,377	32,908,901
PG&E Net Book Value - SF Distribution		480,834,911	493,384,907	505,989,151	518,651,599	531,376,340	544,167,592	557,029,711	569,967,189	582,984,663	596,939,220
PG&E Annual Depr		25,609,351	26,482,476	27,375,319	28,288,346	29,222,036	30,176,878	31,153,375	32,152,043	33,173,410	33,365,707
PG&E NBV Return @ 7.5%	$336,471,070	36,062,618	37,003,868	37,949,186	38,898,870	39,853,225	40,812,569	41,777,228	42,747,539	43,723,850	44,770,442
PG&E NBV Return @ 9.45%	$423,953,549	45,438,899	46,624,874	47,815,975	49,012,576	50,215,064	51,423,837	52,639,308	53,861,899	55,092,051	56,410,756
PG&E Federal and State Inc Tax	$185,283,403	19,858,482	20,376,797	20,897,352	21,420,311	21,945,843	22,474,122	23,005,327	23,539,645	24,077,267	24,653,590

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Table 4-6
Estimate of Revenue Requirements 2002 - 2011
Municipal Versus PG&E - High Cost Case
Transfer Price RCNLD - Sinking Fund Depreciation

Municipal Costs	Net Present Value @12.5% 30 Yr NPV	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Distribution O&M Expense	$206,596,136	$21,050,932	$21,694,380	$22,356,197	$23,037,547	$23,738,992	$24,461,110	$25,204,497	$25,969,766	$26,757,545	$27,568,482
System Power, Transmission & CTC	1,834,457,174	183,431,000	190,537,000	197,695,000	204,876,000	212,076,000	216,912,000	219,042,000	226,694,000	234,377,000	242,091,000
Franchise Fees and Property Tax	61,355,007	6,489,409	6,672,675	6,857,131	7,042,695	7,229,391	7,405,371	7,568,977	7,761,409	7,955,273	8,155,515
Customer Accounts Expense	132,646,579	13,515,873	13,929,002	14,353,926	14,791,930	15,241,757	15,705,397	16,182,693	16,674,038	17,179,837	17,700,503
Customer Service & Info Expense	111,547,920	11,366,078	11,713,496	12,070,832	12,438,715	12,817,448	13,207,343	13,608,721	14,021,915	14,447,262	14,885,113
Administrative and General Expense	76,634,408	7,808,590	8,047,269	8,292,762	8,545,593	8,805,693	9,073,555	9,349,305	9,633,172	9,925,389	10,226,197
SF 230 kv Cable O&M	6,451,001	687,194	704,374	721,983	740,033	758,534	777,497	796,934	816,858	837,279	858,211
Total Operating Costs	2,429,688,224	244,349,076	253,298,196	262,347,831	271,472,512	280,667,815	287,542,272	291,753,127	301,571,158	311,479,586	321,485,021
Depreciation - Plant and Equipment	422,135,015	49,599,345	50,084,735	51,081,227	52,108,806	53,175,068	54,281,507	55,150,159	55,961,312	56,805,303	57,681,827
Amort. of Capitalized Development Costs	8,327,556	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000
Interest on Debt	498,712,539	74,928,332	73,194,185	71,462,912	69,735,157	68,011,111	66,290,976	64,595,926	62,933,748	61,305,588	59,712,760
Total Revenue Requirements	$3,358,863,334	$370,026,753	$377,727,116	$386,041,970	$394,466,475	$403,003,995	$409,264,755	$412,649,213	$421,616,218	$430,740,477	$440,029,608
PG&E Costs											
Distribution O&M Expense	234,482,336	$23,892,372	$24,622,672	$25,373,821	$26,147,139	$26,943,264	$27,762,853	$28,606,583	$29,475,146	$30,369,259	$31,289,656
System Power, Transmission & CTC	1,834,457,174	183,431,000	190,537,000	197,695,000	204,876,000	212,076,000	216,912,000	219,042,000	226,694,000	234,377,000	242,091,000
Franchise Fees and Property Tax	61,355,007	6,489,409	6,672,675	6,857,131	7,042,695	7,229,391	7,405,371	7,568,977	7,761,409	7,955,273	8,155,515
Customer Accounts Expense	132,646,579	13,515,873	13,929,002	14,353,926	14,791,930	15,241,757	15,705,397	16,182,693	16,674,038	17,179,837	17,700,503
Customer Service & Info Expense	111,547,920	11,366,078	11,713,496	12,070,832	12,438,715	12,817,448	13,207,343	13,608,721	14,021,915	14,447,262	14,885,113
Administrative and General Expense	81,375,062	8,291,635	8,545,079	8,805,758	9,074,223	9,350,420	9,634,851	9,927,659	10,229,087	10,539,381	10,858,796
Total Operating Costs	2,455,864,078	246,986,367	256,019,924	265,156,468	274,370,702	283,658,280	290,627,815	294,936,633	304,855,595	314,868,012	324,980,583
Depreciation	249,830,598	25,609,351	26,482,476	27,375,319	28,288,346	29,222,036	30,176,878	31,153,375	32,152,043	33,173,410	33,365,707
Return and Income Tax	609,236,951	65,297,381	67,001,670	68,713,327	70,432,887	72,160,907	73,897,959	75,644,635	77,401,544	79,169,317	81,064,346
Total Revenue Requirements	$3,314,931,628	$337,893,099	$349,504,071	$361,245,114	$373,091,936	$385,041,223	$394,702,651	$401,734,643	$414,409,182	$427,210,739	$439,410,636
Annual Revenue Requirement Difference Municipal versus PG&E	$43,931,706	$32,133,654	$28,223,045	$24,796,856	$21,374,540	$17,962,772	$14,562,104	$10,914,570	$7,207,036	$3,529,737	$618,972
% Change In NPV From PG&E 30 Yrs	1.33%										
		2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
RCNLD NBV		$976,044,429	$954,072,460	$932,138,821	$910,252,091	$888,414,818	$866,629,681	$845,179,018	$824,166,636	$803,607,838	$783,520,138
RCNLD Annual Depr & Amort		49,599,345	50,084,735	51,081,227	52,108,806	53,175,068	54,281,507	55,150,159	55,961,312	56,805,303	57,681,827
PG&E Net Book Value - SF Distribution		480,834,911	493,384,907	505,989,151	518,651,599	531,376,340	544,167,592	557,029,711	569,967,189	582,984,663	596,939,220
PG&E Annual Depr		25,609,351	26,482,476	27,375,319	28,288,346	29,222,036	30,176,878	31,153,375	32,152,043	33,173,410	33,365,707
PG&E NBV Return @ 7.5%	$336,471,070	36,062,618	37,003,868	37,949,186	38,898,870	39,853,225	40,812,569	41,777,228	42,747,539	43,723,850	44,770,442
PG&E NBV Return @ 9.45%	$423,953,549	45,438,899	46,624,874	47,815,975	49,012,576	50,215,064	51,423,837	52,639,308	53,861,899	55,092,051	56,410,756
PG&E Federal and State Inc Tax	$185,283,403	19,858,482	20,376,797	20,897,352	21,420,311	21,945,843	22,474,122	23,005,327	23,539,645	24,077,267	24,653,590

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Table 4-7
Estimate of Revenue Requirements 2002 - 2011
Municipal Versus PG&E - Lower Boundary
Transfer Price Net Book Value

Municipal Costs	Net Present Value @12.5% 30 Yr NPV	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Distribution O&M Expense	$206,596,136	$21,050,932	$21,694,380	$22,356,197	$23,037,547	$23,738,992	$24,461,110	$25,204,497	$25,969,766	$26,757,545	$27,568,482
System Power, Transmission & CTC	1,834,457,174	183,431,000	190,537,000	197,695,000	204,876,000	212,076,000	216,912,000	219,042,000	226,694,000	234,377,000	242,091,000
Franchise Fees and Property Tax	61,355,007	6,489,409	6,672,675	6,857,131	7,042,695	7,229,391	7,405,371	7,568,977	7,761,409	7,955,273	8,155,515
Customer Accounts Expense	132,646,579	13,515,873	13,929,002	14,353,926	14,791,930	15,241,757	15,705,397	16,182,693	16,674,038	17,179,837	17,700,503
Customer Service & Info Expense	111,547,920	11,366,078	11,713,496	12,070,832	12,438,715	12,817,448	13,207,343	13,608,721	14,021,915	14,447,262	14,885,113
Administrative and General Expense	76,634,408	7,808,590	8,047,269	8,292,762	8,545,593	8,805,693	9,073,555	9,349,305	9,633,172	9,925,389	10,226,197
SF 230 kv Cable O&M	6,451,001	687,194	704,374	721,983	740,033	758,534	777,497	796,934	816,858	837,279	858,211
Total Operating Costs	2,429,688,224	244,349,076	253,298,196	262,347,831	271,472,512	280,667,815	287,542,272	291,753,127	301,571,158	311,479,586	321,485,021
Depreciation - Plant and Equipment	174,734,308	15,434,363	15,919,753	16,916,245	17,943,824	19,010,086	20,116,525	20,985,177	21,796,330	22,640,321	23,516,845
Amort. of Capitalized Development Costs	8,327,556	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000
Interest on Debt	258,650,920	26,619,559	27,447,785	28,278,885	29,113,504	29,951,832	30,794,071	31,661,395	32,561,590	33,495,803	34,465,350
Total Revenue Requirements	$2,871,401,009	$287,552,998	$297,815,734	$308,692,962	$319,679,841	$330,779,734	$339,602,868	$345,549,699	$357,079,078	$368,765,710	$380,617,215
PG&E Costs											
Distribution O&M Expense	234,482,336	$23,892,372	$24,622,672	$25,373,821	$26,147,139	$26,943,264	$27,762,853	$28,606,583	$29,475,146	$30,369,259	$31,289,656
System Power, Transmission & CTC	1,834,457,174	183,431,000	190,537,000	197,695,000	204,876,000	212,076,000	216,912,000	219,042,000	226,694,000	234,377,000	242,091,000
Franchise Fees and Property Tax	61,355,007	6,489,409	6,672,675	6,857,131	7,042,695	7,229,391	7,405,371	7,568,977	7,761,409	7,955,273	8,155,515
Customer Accounts Expense	132,646,579	13,515,873	13,929,002	14,353,926	14,791,930	15,241,757	15,705,397	16,182,693	16,674,038	17,179,837	17,700,503
Customer Service & Info Expense	111,547,920	11,366,078	11,713,496	12,070,832	12,438,715	12,817,448	13,207,343	13,608,721	14,021,915	14,447,262	14,885,113
Administrative and General Expense	81,375,062	8,291,635	8,545,079	8,805,758	9,074,223	9,350,420	9,634,851	9,927,659	10,229,087	10,539,381	10,858,796
Total Operating Costs	2,455,864,078	246,986,367	256,019,924	265,156,468	274,370,702	283,658,280	290,627,815	294,936,633	304,855,595	314,868,012	324,980,583
Depreciation	249,830,598	25,609,351	26,482,476	27,375,319	28,288,346	29,222,036	30,176,878	31,153,375	32,152,043	33,173,410	33,365,707
Return and Income Tax	609,236,951	65,297,381	67,001,670	68,713,327	70,432,887	72,160,907	73,897,959	75,644,635	77,401,544	79,169,317	81,064,346
Total Revenue Requirements	$3,314,931,628	$337,893,099	$349,504,071	$361,245,114	$373,091,936	$385,041,223	$394,702,651	$401,734,643	$414,409,182	$427,210,739	$439,410,636
Annual Revenue Requirement Difference Municipal versus PG&E	($443,530,619)	($50,340,101)	($51,688,337)	($52,552,152)	($53,412,095)	($54,261,489)	($55,099,783)	($56,184,944)	($57,330,104)	($58,445,029)	($58,793,421)
% Change In NPV From PG&E 30 Yrs	-13.38%										
		2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
NBV Including $5million PS		$331,927,449	$344,120,462	$356,351,804	$368,630,056	$380,957,765	$393,337,610	$406,051,928	$419,204,528	$432,810,712	$446,887,994
Annual Depr & Amort		15,434,363	15,919,753	16,916,245	17,943,824	19,010,086	20,116,525	20,985,177	21,796,330	22,640,321	23,516,845
PG&E Net Book Value - SF Distribution		480,834,911	493,384,907	505,989,151	518,651,599	531,376,340	544,167,592	557,029,711	569,967,189	582,984,663	596,939,220
PG&E Annual Depr		25,609,351	26,482,476	27,375,319	28,288,346	29,222,036	30,176,878	31,153,375	32,152,043	33,173,410	33,365,707
PG&E NBV Return @ 7.5%	$336,471,070	36,062,618	37,003,868	37,949,186	38,898,870	39,853,225	40,812,569	41,777,228	42,747,539	43,723,850	44,770,442
PG&E NBV Return @ 9.45%	$423,953,549	45,438,899	46,624,874	47,815,975	49,012,576	50,215,064	51,423,837	52,639,308	53,861,899	55,092,051	56,410,756
PG&E Federal and State Inc Tax	$185,283,403	19,858,482	20,376,797	20,897,352	21,420,311	21,945,843	22,474,122	23,005,327	23,539,645	24,077,267	24,653,590

Table 4-8: Calculation of Factor Differences, CCSF Muni v. PG&E (BAU) 30-Year NPV (for Table 4-3, from Tables 4-4, 4-5 and 4-6)

	Base Case		Low Cost Case		High Cost Case	
Distribution O&M+AG&O+CABIS						
Muni	$289,681,544		$289,681,544		$289,681,544	
PG&E	315,857,398		315,857,398		315,857,398	
Difference	(26,175,854)	(26,175,854)	(26,175,854)	(26,175,854)	(26,175,854)	(26,175,854)
PG&E SF COS 30 yrs	$3,314,931,628		$3,314,931,628		$3,314,931,628	
% Difference	-0.79%		-0.79%		-0.79%	
CCSF Profit Elimination Savings						
PG&E Rate Base*7.5%	$336,471,070		$336,471,070		$336,471,070	
PG&E Rate Base*9.45%	423,953,549		423,953,549		423,953,549	
Difference	(87,482,478)	(87,482,478)	(87,482,478)	(87,482,478)	(87,482,478)	(87,482,478)
PG&E SF COS 30 yrs	$3,314,931,628		$3,314,931,628		$3,314,931,628	
% Difference	-2.64%		-2.64%		-2.64%	
Federal & State Income Taxes	($185,283,403)	($185,283,403)	($185,283,403)	($185,283,403)	($185,283,403)	($185,283,403)
PG&E SF COS 30 yrs	$3,314,931,628		$3,314,931,628		$3,314,931,628	
% Difference	-5.59%		-5.59%		-5.59%	
SF Distribution Acqusition Premium						
Return:						
Acquistion Cost @ 7.5%	426,086,050		322,525,345		498,712,539	
PG&E SF @7.5%	336,471,070		336,471,070		336,471,070	
Difference	89,614,979	$89,614,979	(13,945,725)	($13,945,725)	162,241,469	$162,241,469
PG&E SF COS 30 yrs	$3,314,931,628		$3,314,931,628		$3,314,931,628	
% Difference	2.70%		-0.42%		4.89%	
Depreciation & Amort.						
Acqistion Cost	356,693,967		251,073,058		430,462,571	
PG&E SF Depr	249,830,598		249,830,598		249,830,598	
Difference	106,863,369	106,863,369	1,242,460	$1,242,460	180,631,973	$180,631,973
PG&E SF COS 30 yrs	$3,314,931,628		$3,314,931,628		$3,314,931,628	
% Difference	3.22%		0.04%		5.45%	
Total Acquistion Diff	5.93%		-0.38%		10.34%	
Total Difference	-3.09%	(102,463,387)	-9.40%	(311,645,001)	1.33%	43,931,706

CHAPTER 5: Other Factors Affecting Municpalization

Overview and Summary of Chapter 5

In order to decide whether to municipalize electric service in SF, we must consider factors in addition to the pure economics of the muni and business-as-usual (BAU[1]) options to be sure that there is a reasonable way to "get there" if the economics look attractive. We need a general understanding of the key legal processes involved and a roadmap and time-table for the main steps that must be followed. In addition, we must consider whether there are alternative financial approaches that may be available, and we should consider the benefits and processes in light of the risks. Further, we must also be concerned about the effects on other matters of public policy, such as environmental impacts, from municipalization. And we want to know how the present assessment compares to previous reviews of SF electric municipalization. Task five of the work scope in the contract for this project was designed to address these issues, and so we review them in turn in this chapter, first in summary in this section and then in more detail in the six sections of this chapter.

Legal and Regulatory Framework: In section 5.A, we review three legal and regulatory elements: condemnation, the taking of PG&E's SF electric-utility system; the state and federal regulatory processes to which CCSF would be subject as a result of providing retail electric-utility service; and the legal standards that would attend CCSF's ratemaking and provision of utility service. The latter two items do not raise any significant issues for the municipalization decision, but the condemnation process raises two of them. First, as discussed in section 5.A *infra*, section 1245.250(b) of the California Code of Civil Procedure, added in 1992, looks innocuous on its face, but in fact it raises significant risks and requires an abundance of caution, especially in making a

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[1] Under BAU, PG&E continues to provide electric-distribution utility service and electricity supply is provided through an increasingly competitive and deregulated industry as provided by AB 1890.

strong showing of the public benefits of municipalization. Failure to make a strong showing on the total net social benefits (i.e., maximum public good and least private injury) of municipalization and thus that the public interest and necessity favors it could now get the condemnation case dismissed before it even really gets started. Previously, there was no such trip-wire. In addition, the endgame of a condemnation action is fraught with problems, even if the condemnor were to win on its proposed valuation. In particular, the rules applicable to condemnation proceedings require that the condemnor be ready to proceed almost immediately upon a verdict; in a matter involving huge funding such as this one does, that means that the financing must be ready almost on a standby basis before the case ends.

Time Table: Major Milestones and Costs of Process: As discussed in earlier chapters, the valuation greatly affects the pure rate-economics of municipalization, because it is such a large cost and especially because it has such a wide range of uncertainty (and because 74% of SF electric service costs are not affected by the muni/IOU choice). Further, while our estimate of the income capitalization value may reasonably be considered definitive (subject, of course, to later updating), definitive versions of the various replacement-cost values generally require an inventory-inspection study -- which may produce results somewhat different from ours. While we believe our replacement-cost estimates are as sound as can be done without an inventory-inspection study, there is no way to tell whether the estimates from an inventory-inspection study are more likely to increase or decrease our replacement-cost valuation estimates, nor whether they may change by a lot or only a little. Hence, the results for two of our three realistic cases, including the base case, are uncertain. Moreover, because the base-case results show only modest benefits from municipalization, and the realistic range of rate outcomes spans the break-even point and indicates there is a material chance that municipalization will yield higher costs -- although a greater chance that they will be lower -- resolution of this uncertainty is key to determining whether to proceed. This need drives the municipalization process from the front end, while the condemnation litigation steers it on the back end. In between are various procedural requirements which take some time. In section 5.B, we lay out a schedule that accommodates all of these requirements in a prudent minimum of time. It shows that the earliest reasonable date for beginning municipal operation is the start of the year 2002.

Because our economic assessment shows that the net benefits or costs from municipalization are not sensitive to whether it is done earlier or later, our schedule has been based on our reckoning of the earliest practical date. If the process is delayed or speeded up, the economics of municipalization will not be changed.

Other Viable Financial Approaches: Section 5.C discusses one possible alternative method of financing; a sale-and-leaseback financing vehicle. This approach is theoretically possible and could provide the capital necessary to acquire the SF distribution system without the requirement to issue bonds. However, there would be no net financial benefits from such a transaction.

Major Risks of Electric-Utility Municipalization in SF: By structuring our analysis in terms of four cases centered on a base case, a realistic range and a boundary case, we have incorporated into the results presented in chapter 4 most of the risks, both negative and positive. The case and factor analyses show that the dominant risk is the uncertainty in the valuation that will be placed on PG&E's SF distribution system in a condemnation case to determine what CCSF must pay to become a muni electric utility. While the schedule laid out in section 5.B is keyed to resolving early as much of that uncertainty as possible, most of it remains until the jury brings in its verdict. In section 5.D, we summarize the valuation, procedural and other risks.

Environmental Impacts from Municipalization: Our analysis in section 5.E concludes that there are not likely to be any significant negative or positive environmental impacts from municipalization.

Review of Prior Municipalization Studies: The most recent other study on this subject was done in 1988-89 at the University of California. This study concluded that power-supply-costs savings in municipalization would be the basis for acquiring the PG&E system. In addition, the study concluded that "tax free" bond issues could not be used to finance the acquisition of the SF distribution system. See section 5.F for a review of this study and comparison of its results to ours.

A. The Legal and Regulatory Framework Involved in Municipalization

1. Legal Matters: The Condemnation Process

The legal process for a public agency taking over a utility's distribution system to establish municipal service is called "condemnation". This is the court action by which the agency takes the property for public use and a court (almost always in a jury trial) sets the compensation (based on valuation evidence) the public agency (or condemnor) must pay for the property taken from the owner (the condemnee). The main item the California condemnor needs to get into court to be allowed to take the property and have a trial on the compensation (valuation) is a resolution of public necessity, passed by a vote of at least two-thirds of its board, which states that the agency has found the taking to be, all things considered, in the public interest -- i.e., a matter of public necessity. In particular, under section 1240.030, the CCSF would have to find affirmatively on items a, b and c:

> The power of eminent domain may be exercised to acquire property for a proposed project only if all of the following are established:
> (a) The public interest and necessity require the project.
> (b) The project is planned or located in the manner that will be most compatible with the greatest public good and the least private injury.
> (c) The property sought to be acquired is necessary for the project.

Another code section adds to this requirement. As stated in the summary on this issue, section 1245.250(b) of the California Code of Civil Procedure, added in 1992, looks innocuous at first. It addresses the resolution of public necessity that a public body such as CCSF must adopt as the primary step in going forward with a matter such as electric-utility municipalization. It reads:

> (b) If the taking is by a local public entity, other than a sanitary district exercising the powers of a county water district pursuant to Section 6512.7 of the Health and Safety Code, and the property is electric, gas, or water public utility property, the resolution of necessity creates a rebuttable presumption that the matters referred to in Section 1240.030 are true. This presumption is a presumption affecting the burden of proof.

Before this provision was added to California law, the matters referred to in section 1240.030 (findings of public necessity -- here, by the CCSF Board of Supervisors) were conclusive, not rebuttable presumptions. Thus, a court hearing a condemnation case had merely to be shown that the condemnor had followed proper procedure and, having an evidentiary basis, had made findings and conclusions of public necessity, and then the court was required to accept as a basic premise that the taking of the utility property was in the public necessity and should proceed. Usually, then, the only significant remaining question was the amount of compensation to be paid by the public to the condemnee. With section 1245.250(b) added, the law now essentially requires the court to hold before the judge (i.e., even before a jury is picked) a hearing on the threshold three issues of public necessity, giving the condemnee (here, PG&E) an opportunity to rebut the resolution of necessity adopted by the condemnor (CCSF) and to put on virtually a full case to show the contrary -- i.e., that continuing its service is more beneficial to the overall public interest and thus the taking is not in the public interest. One could reasonably expect PG&E to put on a full showing attempting to rebut each of the three points in section 1245.030. Then the judge will determine whether (s)he thinks the condemnee has met its burden of proof to disprove the resolution of the public agency.

This provision raises a new element of risk in undertaking a condemnation action to create a muni utility. Formally, it does not add a new substantive requirement to the process, but it does require an abundance of caution in adopting the resolution of necessity. That is, one may presume that public agencies have always prudently observed the standard that the taking must be clearly shown to be in the public interest and thus a matter of necessity (as demonstrated, for example, by the CCSF commissioning this study). However, before 1992, that issue did not have to be proven to a possibly skeptical (and, in any event, neutral) trier of fact, as the hearing on this issue before the trial judge will now require. Because there have been no major California condemnations of such utility systems since this section was adopted (but only sub-division annexations, etc. which almost always settle because they are too small for parties to justify the cost to litigate extensively), there has been no real test of this provision of the law to see how it will actually be applied. However, because it applies to threshold matters of fact, even some case history would not be very instructive, because each situation and each court tends to be unique in this regard. In any event, this section raises a new

matter for trial, and thus it requires that CCSF go into its condemnation case to municipalize SF electric service prepared to litigate this matter extensively from the start. That is, one can presume that PG&E will fight it aggressively because its first letter acknowledging ETAG's data requests in this matter prominently featured the statement: "PG&E's system in San Francisco is not for sale." It agreed to respond, "without, in any way, compromising our opposition to any forced takeover."[2]

From another viewpoint, this provision may create an even more pernicious problem for CCSF as a condemnor in this matter. As this report has shown, if the argument for municipalization is based on rate impacts, then the entire case on municipalization economics rides on the valuation of the system in a condemnation action, and thus the case for public necessity seems to rest on assuming at least some limits on the outcome of the condemnation trial. That is, if the findings of public necessity rest on a conclusion that the transfer price determined in the condemnation valuation is no more than, say, \$950-million (as our case results indicate for the simple rate impacts, via interpolation), then to meet the threshold issue of public necessity in order to proceed to trial on valuation, CCSF would have to convince the court to adopt a conclusion that a value above \$950-million is not a possible outcome of the trial. As indicated in previous chapters, we believe that the best value is between the \$505-million income-capitalization value and the \$795-million RCLD(SL) + GCV + PS value, but we also recognize that evidence on various replacement-cost estimates of \$999-million or even a higher value is admissible and that a jury verdict of up to the \$999-million figure or more can not be ruled out. Hence, CCSF would need to argue other notions to show that it meets the threshold test, in view of the possible range of outcomes of the main trial issue.

Therefore, this provision requires CCSF to find other bases than just the projected rate impacts to support its finding of necessity. And in the process leading up to filing a condemnation case, these other bases will have to be developed and documented extensively and with caution to assure that the condemnation action survives the threshold issue -- i.e., that the resolution of necessity is not effectively rebutted. At least three approaches to showing the public interest are possible here:

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[2] Letter from Thomas P. Evans to Ronald L. Knecht, 13 August 1996.

- First, CCSF could show that non-economic matters (e.g., control factors) satisfy the section 1240.030 tests. For example, our figures address a large part of the public interest at stake in this matter, without purporting to consider all public-interest factors, some of which we recognize may not be amenable to quantification in the utility-rate-oriented economics on which this study is based. On the other hand, this approach may seem slightly disingenuous if much of the impetus for municipalization comes from claims that it will lower rates.

- Second, The City could argue that a probabilistic analysis of the likely condemnation valuation shows that the expected value of the effort yields a significant net economic benefit, even if not an absolutely certain outcome. The estimates and resulting rate-impact ranges developed here (together with the probabilities we have suggested for the various valuations) would provide such a basis. In our view, this is a sound basis, but a sophisticated one that requires some comfort with probabilistic analysis as a public-policy tool. Thus, documenting such a basis to a court requires advance preparation at the Certificate of Necessity stage.

- Finally, the economic analysis discussed in section 4.A.3 and illustrated in Table 4-3 provides an economic basis that does not ride upon exact limits on the valuation outcome, but merely upon the belief that the trier of fact is not likely to err greatly or systematically against The City on the condemnation valuation. In our view, this is the most sound analysis of all, but it also requires comfort with the subtle economic analyses that show why some rate impacts are illusory, not real. Again, documenting such a basis to a court requires advance preparation at the Certificate stage.

None of these approaches, of course, precludes the others, so the showing could be based on all three of them. In any event, it should also be tailored to the three specific findings of fact, items a-c in section 1245.030.

The condemnation legal proceeding, itself, should be undertaken only after The City is certain it wants to proceed; a change in utility ownership and operation is a process one would not want to

reverse due to the dislocations such a change causes all parties (CCSF, PG&E and electric-utility customers). Pre-judgment possession provisions are available to a condemnor, so actually filing a condemnation case could be delayed until SF is ready to start operations. However, this approach requires deposit of the probable amount of compensation at the start, and besides being subject to motions to vacate, stay the effective date (which otherwise is within 90 days) or increase the amount of the deposit, it is also vulnerable on more serious grounds. Primarily, they are that the condemnation action could fail, resulting in CCSF having to return the problem and pay all of PG&E's costs (including costs of reoccupation and re-initiation of operations) and other damages. The condemnation action could fail for at least two reasons: first, as a result of section 1245.250(b) discussed above, CCSF could fail to meet the threshold right-to-take issue; and second, the valuation verdict could come in so high that The City would conclude it is not in the public interest to continue with municipal service (or, even, that it simply could not finance the additional amount at the time). In any event, the potential exposures are so huge under this approach that the better course appears to be to proceed with the condemnation early and be ready to move when the trial is over. This approach also has problems, too, because it would require CCSF to prepare to begin operations within 30 days of the completion of a trial that may be subject to unforeseen delays. Also, the 30-day period in this approach compounds the problem of arranging the truly large levels of financing (hundreds of millions of dollars, with the exact amount uncertain before the verdict) on which CCSF would have 90 days in the early possession route.

In any event, this matter should be studied closely to balance the risks and benefits before choosing a course. In setting a schedule, we have assumed, for conservative planning, that early possession would not be elected and that CCSF would want to file its action at least a year before the planned possession date. Note, however, that even this choice is subject to some risk, because if The City plans for a decision a year later and it comes within six months, then the City would have to be ready to proceed within 30 days, or lose its verdict.

A final legal risk of note is that the condemnation action may require CCSF actions to comply with the California Environmental Quality Act (CEQA), resulting possibly in an Environmental

Impact Report (EIR) or other CEQA actions. If so, due to the protracted preparation and proceedings that will be required in connection with it, The City should proceed on this early in the process -- perhaps as soon as a voter referendum approves a municipalization proposal (if one does).

Thus, before condemnation, SF should:

- Complete a detailed feasibility study based on an inventory and valuation survey;
- Assure that the proposal is consistent with The City's General Plan and its implementing elements;
- Assure that the requirements of CEQA have been satisfied;
- Secure any needed permissions from the Local Agency Formation Commission (LAFCO);
- Have the Board of Supervisors pass the necessary resolutions of public necessity by at least a two-thirds vote;
- Arrange financing (which will require voter approval at least once);
- Begin to develop detailed plans, policies, organization and management for operation; and
- Begin to staff the new utility.

All of this process must be conducted in compliance with California's Brown Act and other state and local laws, which requires extensive public disclosure.

As a direct consequence of this section 1245.250(b), the best plan would be to complete the extended valuation study first, and then make a case to the voters in an election, based on the study's results. If the proposal is ratified in such an informed manner, and if the Board of Supervisors is careful to indicate its understanding and prudent reliance of a sound analysis that does not assume limits on the valuation that cannot be assured, then the chances that PG&E could successfully rebut a finding of necessity would be greatly reduced.

A final note on legal and related risks: The APPA paper, "Straight Answers to False Charges Against Public Power", addresses these matters, beginning at page 19 and elsewhere. If The City elects to proceed with municipalization, it should enlist APPA's help, because it specializes in this issue.

2. Regulatory Framework for CCSF Muni Electric Utility

Turning to regulation, FERC and CPUC regulation is described in chapter three, which notes that it is changing rapidly. CCSF/HHWP would be subject to no new regulation by the California Energy Commission (CEC), because it already is subject to that agency's jurisdiction, but retail service may trigger additional reporting requirements to the CEC. Finally, the legal standards applying to municipal utility ratemaking and other aspects of providing utility service give CCSF greater leeway than an IOU has under state-issued monopoly franchise and regulation. As long as the SFPUC has a reasonable basis in the public record for its rates and actions, it will have great freedom to proceed without interference by the courts.

B. Time Table: Major Milestones, Costs: SF Electric Municipalization

A one-page time table with actions that appear to satisfy the basic requirements of the law and sound public policy for such a process appears on the next page. It also contains very rough estimates of costs of the various actions, but they are extremely uncertain at this point. Nonetheless, these costs have been included in our analysis in chapter 4. As a result of the valuation uncertainty due to various factors discussed in preceding chapters, before proceeding beyond the extended valuation study, we recommend that the CCSF should have a basis for a conclusion that municipalization is in the public interest and thus a sound statement of the public necessity findings. We believe our study provides a basis for this policy decision, but the more extensive valuation study would improve the basis for and help refine the specific terms of the public-necessity conclusion.

TIME TABLE: CCSF ELECTRIC MUNICIPALIZATION

97-98 ***Extended valuation study*** should focus on facilities inventory, condition assessment and valuation: conductor- and circuit-miles, transformers, specialized equipment, substations and street lights. Inventory should be related to installment dates, using PG&E maps and job records, where they exist, and should survey condition at same time. Such inventories usually come later, but are put at front here because the decision to proceed turns on the system valuation, and analysis shows that even if RCLD(SL) + GCV + PS is used, municipalization may be attractive, *depending on exact RCLD estimate*. This step takes time, because the Board of Supervisors will probably need to adopt findings and orders requiring PG&E to make available its maps and records. Study should also update this one for developments over next two years in electric-utility reregulation and restructuring. Cost: ~ $1-million.

1999 ***Voter preference/advisory referendum*** based on results of extended valuation study and public-education effort if result is positive or close. ***CEQA and General-plan*** actions begun to assure consistency with proposal, via proceedings and revisions. Cost: ~ $400,000.

2000 ***Resolution of Necessity adopted by Board of Supervisors setting implementation plans; condemnation proceeding filed mid-year.*** SFPUC develops detailed plans, policies, organization and management for operation; ***management staffing begun***. Cost ~ $4-million.

2001 ***Financing set by revenue-bond referendum; implementation begins with staffing up; and condemnation action ends successfully late in year.*** Cost very uncertain: ~ $17.6-million.

2002 ***Take control of system and begin municipal retail electric-utility service in SF.***

Notes: See next page.

Notes to CCSF Municipalization Time Table on Previous Page

1) 1997-98 extended valuation study based on seven person-years (PY; 2000 hours) at \$70/hour: \$1-million.

2) 1999 Referendum costs, including legal opinions and Board of Supervisors actions: \$75,000; General Plan and related actions, including lawyer and related time and staff and consultant work \$75,000; Voter education efforts in connection with referendum: \$250,000. These figures reflect, we believe, the abundance of caution needed to secure the public necessity findings. If a full EIR is required, the cost (based on experience with managing them) would be about another \$500,000 in 1999-2000.

3) 2000 Board Resolution of Necessity, including staff, legal and consultant help: \$100,000; Administrative, general and overhead (AG&O) costs for planning, organization, etc. in first half of year: \$200,000; AG&O for second half of year, based on one-quarter of first-operating-year AG&O cost: \$1.7-million; Legal fees for condemnation case: five lawyer PYs at \$200/hour.

4) 2001 AG&O for first half of year, based on one-quarter of full complement again: \$1.7-million; AG&O for second half, based on full complement for half year: \$3.4-million; Operations and Maintenance and Customer Accounting, Billing, Information and Services staffing and training, etc., based on one-quarter of first full-year costs: \$9.5-million; Legal fees for condemnation case: 7.5 lawyer PYs at \$200/hour: \$3-million.

Total = \$23-million, or \$23.5-million if EIR required.

Range: \$15-million to \$35-million (-35% to +50%).

C. Financial and Other Approaches to Municipalization

One item in the scope of work is to consider other viable financial approaches to municipalization which could be accomplished within the existing regulatory environment. One possible financing alternative to the issuance of municipal bonds to finance the acquisition of PG&E's SF distribution system could be a sale and lease back financing arrangement. Sale and leaseback financing was a major source of capital to many electric utilities in the 1970s and 1980s. The three key circumstances that underpin sale and lease back financing are: 1) the need to conserve capital on the part of the user of the plant and equipment (the lessee); 2) the inability of the user of plant and equipment (the lessee) to use the income tax deductions that are generated from the plant and equipment, the accelerated deprecation and interest expense; and 3) the ability of lessor to construct a highly leveraged financial package; up to 80% debt capital. In theory, the CCSF could acquire the PG&E distribution system, using a sale and lease back financial vehicle, at an effective cost of money of about 7.5% without having to issue bonds. However, because the cost of money would be about the same as a bond issue, or possible higher if the lessor includes some equity in the lease's capital structure, we do not see any net benefits to The City or the municipal electric utility resulting from this form of financing.

We also considered one possible alternative to full municipalization in which The City would undertake the role of direct-access aggregator. While other entities, such as independent power brokers, will be competing to provide this service, it could be argued that the City has certain natural competitive advantages:

- In the future, The City could have access to municipal preference power, although likely in limited amounts.
- The City could bundle its services in ways which are convenient and specifically tailored to San Francisco customers. For example the City could provide DSM services geared to San Francisco's climate and building types.

- The City has billing and administrative infrastructure in place (e.g., water/sewer billing) which could increase efficiency, and electricity bills could be bundled with these services.

However, any benefits that could be provided by The City in the first two areas are not expected to be materially greater than those provided by independent power brokers and DSM providers. In addition, unless it could be demonstrated, in some manner, that The City will have greater expertise in the power brokering function[3] than private entrepreneurs, we do not consider this approach merits consideration. Finally, the electric utility restructuring plan (AB1890) specifically allows entities such as The City to engage in customer load aggregation without having to create a municipal electric utility in SF.[4]

D. Major Risks of Electric-Utility Municipalization in SF

The major risks are described in chapters 2, 3 and 4 in the factor-cost inputs, as well as in the introduction to this chapter.

A risk not mentioned elsewhere is the possibility that customers might "opt out" of muni-provided bulk power. AB1890 makes provision for customer choice, allowing customers to select another bulk power provider of their choice. The risk is that a CCSF municipal electric utility will incur long-term obligations to buy electricity supply for its retail ratepayers and that some ratepayers will choose to purchase bulk power from another provider thus increasing the muni's average costs.[5]

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[3]Power brokers will aggregate or package individual ratepayer loads and create portfolios of electricity supply to meet the aggregated load.

[4]Section 366 of AB 1890.

[5]However, AB 1890 does contain special provision for municipal electric utilities in this area. For example, IOUs are mandated to implement direct access by 2002, while munis are only required to hold public meetings on this issue. If a municipal electric utility decides to offer direct access, then it is allowed to phase in this program over a longer period of time (2010 versus 2002 for an IOU). Of course, PG&E may face even higher risks and the negative cost impacts on remaining core customers is possibly even greater.

Other down-side risks include at least these:

- The possibility that tens of millions of dollars will be spent on the muni formation process before a definitive feasibility study is completed with a reliable valuation estimate;
- The possibility PG&E may successfully rebut SF in court on its findings of necessity;
- The possibility The City will end up paying much more than it expected to in a condemnation proceeding;
- The possibility muni non-energy operating costs will be much higher than PG&E's;
- It is possible that the SFOC reliability costs, which are currently forecasted to continue to be included in PG&E services area costs, would be allocated directly to SF if a new municipal services territory were established in SF (see chapter 4);
- The possibility bond-issue funding may not be supported by voters or officials; and
- The possibility PG&E will move its headquarters, causing the net loss of thousands of jobs in SF.

E. Environmental Impacts from Municipalization

As discussed in chapter 3, the bulk power resources are unlikely to differ significantly between the business as usual (BAU) and municipalization cases. The City will still rely largely on California's natural-gas-fired generation to meet its incremental changes in loads, with existing renewable, hydropower and base-load generation facilities. The Hunters Point and Potrero generating stations will continue to be dispatched to provide reliability to SF until an alternative source (new generation or transmission facilities) is constructed whether or not the distribution system is municipalized.

One alternative to the continued dependence on Hunters Point and Potrero may be the proposed San Francisco Energy Project or SFEP. The SFEP is a 240 MW cogeneration facility

which is proposed to by located on Port of San Francisco property. The SFEP was awarded a Final Standard Offer 4 contract in PG&E's 1993 competitive bidding process. It won its contract as an alternative to PG&E's proposed repowering of the Hunters Point 2 and 3 units. In addition, the SFEP was granted a "Certificate of Need" by the California Energy Commission.[6] At this point, the future of SFEP project depends on the outcome of a number of legal and regulatory proceedings. However, if the CCSF decides to conduct an extended valuation study on municipalization, it should require that the study include an evaluation of ways to minimize reliability costs, including an evaluation of the role, if any, that the SFEP could play in reliability-cost minimization.

The City may be able to invest in or encourage greater demand-side management (DSM) and conservation efforts under municipalization. DSM investment, on the part of electric utilities across the county and in California, has fallen as a proportion of utility revenues over the last decade as energy and electricity prices have stabilized. In the past, investment in DSM was less attractive than investment in generation because return on generation investment was largely guaranteed, reducing its risk relative to DSM. Restructuring may reduce the push for new public benefit investment (or AB1890 may avoid such a result), but it could also reduce the differences in relative risk exposure between DSM and electricity supply. Customer-driven DSM may increase as a result. However, one factor will change if the SF distribution system is municipalized: the electricity rates to SF electric ratepayers will reflect DSM programs that directly benefit SF and not the average system-wide cost and benefit allocation that will be case in the BAU scenario. AB 1890 contains specific provisions that allow municipal utilities to create an non-bypassable usage charge for conservation, renewables and low-income programs.[7] This mechanism should substantially reduce the risks attendant to these programs in the new competitive market. Unfortunately, not enough is known yet about how DSM investment incentives might change to forecast how much will occur regardless of municipalization.

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[6] *Application for Certification for the San Francisco Energy Company's Cogeneration Project, City and County of San Francisco, California, California Energy Commission*, Docket No. 94-AFC-1, Sacramento, California, P800-96001, February, 1996; California Energy Commission, Decision Docket No.94-AFC-1, March 4, 1996.

[7] Section 385 of AB 1890.

We investigated the possibility that the operations of the Hetch Hetchy hydropower facility would change under municipalization. There are three major constraints which argue against using more of Hetch Hetchy to meet SF electricity loads: 1) the necessity to operate Hetch Hetchy primarily as a water supply system; 2) the CCSF-Modesto Irrigation District agreement on releases from the facility; and 3) the fact that Hetch Hetchy generates significantly on a seasonal basis. During the runoff season, April through July, electric generation is at is maximum capacity, approximately 400 MW. During the rest of the year, electric generation is significantly constrained by scheduled water deliveries, availability of Hetch Hetchy generating units which must be brought down for maintenance in the summer and fall periods, and other factors. As a consequence, electric generation from Hetch Hetchy during the summer and fall, when SF electric loads peak, is between 0 and about 200 MW, depending on the time of day. This means that Hetch Hetchy would only be able to supply between 0 and 200 MW of SF expected 900 MW peak demand.[8] However, if Hetch Hetchy could, in the future, be operated to maximize its electricity production and to meet more of the SF electricity load, that benefit could be passed on to SF electric ratepayers in either the BAU or municipalization option.

Based on our assessment of these issues -- changes in bulk power purchases, including renewable purchases; changes in DSM investment; changes in electricity demand -- the environmental impacts are either negligible or unpredictable at this moment. As the analytic community gains an understanding of how the restructured electricity market might work, and how investment choices might change, this assessment may change as well.

F. Review of Prior Municipalization Studies

In 1988, students at the Graduate School of Public Policy, University of California at Berkeley

[8] During 1994, a representative year, HHW&P generated 1,605,639 MWh and purchased 482,743 MWh for a total of 2,088,382 MWh. District Class 1 sales totaled 270,705 MWh and District Class 3 sales totaled 513,549 MWh. HHW&P provided the Municipal Load and APT Tenants with 760,843 MWh and the remaining 473,450 MWh were used for other purposes.

(UCB) prepared a report entitled, "An Analysis of the Feasibility of Municipalization: Methods and Groundwork." This study did not attempt to directly value the SF transmission and distribution system, but did attempt to calculate the amount of bonded debt the CCSF could service based on the differential between the forecasted electricity rates charged by PG&E and the estimated costs of providing electric service through a CCSF municipal electric utility. The authors simply calculated the amount of additional cash flow that could be used to service bonds used to acquire the SF distribution system assuming: 1) the new muni would continue to charge that same rates as PG&E; 2) the cost of providing electricity, primarily purchase power costs would be lower than that charged by PG&E to retail customers; and 3) non-power supply cost would be the same as those of PG&E.

This study uses a net-revenue-requirements method and, given the constraints of cost of service, and rates in effect at the time of the study, posits the question: What amount of money could be borrowed to pay for the CCSF electric facilities? The answer the authors arrived at was an amount between $300-million and $800-million. The only reason for the difference between these two values is the assumption regarding the purchased power cost. At 4 cents per kWh, escalated, the maximum amount of bonds that could be issued to purchase the SF distribution system is about $800-million. If the assumed purchased power price per kWh increases to 5 cents, then the maximum amount of bonds that could be issued to purchase the distribution system to about $315-million. This study did state that lost taxes to the City of $20.5-million per year if municipalization did occur.

The authors assumed that the City would issue *taxable* A rated revenue bonds with an effective interest rate of between 10% and 10.5%. This assumptions was obtained from a municipal bond brokerage firm; Kelling, Northcross and Nobriga Inc. The authors determined that acquiring the Hunters Point and Potrero units would not be economically unwise given the high costs to operate these units.

In summary, the UCB study attempted to predict the amount of debt that could be supported by municipal rates that would be equal to PG&E rates and assuming that the debt service would be provided by obtaining purchased power below PG&E average cost of supply. With the advent of a

competitive market in power and the virtual elimination of the difference between PG&E's power supply costs and the market price the application of this study's method would produce little or no ability on the part of the CCSF to issue bonds to support the municipalization.

This is not to say that the differential revenue requirements method is not a valid measure of whether or not to municipalize. ETAG's conclusions on the viability of municipalization are based on the difference between the total cost of electricity in our two scenarios. However, the methods employed to arrive at that conclusion are significantly different than those used in the 1988-89 study. Also, that study appears to have given erroneous treatment to tax matters, at least in the context of the requirements of this study. It appears to have ignored benefits to The City and its residents, businesses and other institutions from reduced payments of federal and state income taxes.

CHAPTER 6: Possible Impacts of Electric Industry Restructuring and Alternatives to the Basic Municipalization Model

A. Effects of the Industry Restructuring

1. Introduction

In various sections of this pre-feasibility study, we have made references to the restructuring of the electric utility industry in California and the effect or non-effect that restructuring would have on the economics of municipalization. In this chapter, we summarize key provisions of restructuring and state how and why the new electricity market will affect the economics of municipalization.

2. Background

Provision of electric service to ratepayers consists of three principal functions: power supply (the generation of electricity at power stations supplemented by purchased power), transmission, and distribution. Since their inception, electricity utilities have generally provided all three functions in one fully integrated franchised entity. Electric ratepayers were captive to the utility/regulator electricity supply decisions (also known as resource planning). Clearly, many of the electricity supply decisions of the last 25 years have turned out to be wrong. California electricity supply costs are now 50% higher than the national average. During the past four years, the California Public Utilities Commission (CPUC) has been searching for alternatives to this traditional electricity supply model.

In December 1995, the CPUC issued its order on restructuring the investor-owned utilities in California. The stated goal of the CPUC was "discovering and deploying strategies and mechanisms

which would place sustainable, downward pressure on the cost of electricity to all classes of California ratepayers".[1] The mechanism that the CPUC chose to achieve this goal was market competition and customer choice.

In order to implement its "market solution," the CPUC adopted a new structure whereby the regulated investor-owned electric utilities in California will transfer control of their transmission system to an Independent System Operator (ISO) which will be responsible for coordinating the dispatch and delivery of power over the statewide transmission system. In addition, the electric utility would be required to divest itself of a substantial portion of its electric generating assets. Therefore, restructuring will "dis-integrate" the electric utility and leave it with one remaining non-competitive (franchised monopoly) function: the distribution of electricity to retail customers.

The CPUC stated that, by 1 January 1998, many retail customers will be allowed to participate in the new electricity supply market via direct access. With direct access, customers can choose to purchase power according to default rates or on terms and conditions negotiated directly with competing non-utility generators. The CPUC stated that its goal was that all customers would have the opportunity to participate in the market within five years -- i.e., by 2001.

Because market prices for power supply are now quite below the electric utilities' costs, and are expected to remain so well into the future, the CPUC ordered that the IOUs' above-market costs be written off and collected from ratepayers by the year 2005 through a non-bypassable Competition Transition Charge (CTC). The net result would be the creation of a competitive market in electricity supply and lower electricity rates.

The California Legislature passed and the Governor signed AB1890 into law in September 1996. As we stated in chapter 3 of this report, nearly all of the CPUC's policy provisions in its December 1995 decisions were enacted into law. AB 1890 requires that all retail customers of

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[1] CPUC Decision 96-01-009, 10 January 1996, page 5. Decision 96-01-009 modified Decision 95-12-063.

investor-owned electric utilities have "direct access" rights by 1 January 2002, as opposed to the 2005 date specified in the CPUC decision. AB 1890 mandates a 20% reduction in retail electric rates for residential and small commercial electric ratepayers of investor owned electric utilities and provides a financing mechanism, California State Bonds, to finance that a portion of the CTC allocated to residential and small commercial customers in order to facilitate the first 10% reduction in rates.

Within the past year, FERC finalized its 900-page Mega-NOPR (Notice of Proposed Rulemaking) on Open Access and issued a decision denying an application by a municipal entity (Palm Springs California) for a wheeling request under the Federal Power Act Section 212.[2]

These two regulatory decisions and the enactment of AB 1890 into law, taken together, produce a mixed result for the economics of municipalization and for alternatives to full municipalization ("muni-lite"), as discussed below.

B. Impacts on Municipalization

The most positive benefit of these three policy pronouncements, on the issue of the economic benefits and costs of municipalization, is that a great deal of uncertainty about the future of the electricity market in California has been settled. While the future market prices of electricity and some implementation details are still unknown, the factors that will drive the economic analysis of municipalization have been narrowed. This is especially true in the area of power supply costs. As we stated in chapter 3, the most reasonable assumption is that there will be no significant differences in energy-supply costs to SF electric ratepayers, whether or not municipalization occurs.

One specific possible benefit in favor of municipalization in San Francisco of these policy changes is the strong likelihood that the CCSF would not have to purchase the costly Potrero and

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[2] FERC decision in Docket No. TX-96-7-000.

Hunters Point generating stations that provide reliability to SF at a very high operating cost. The reliability costs or SFOC costs will be included in the average reliability costs for the PG&E system.

In fact, in late October PG&E announced that it will sell one of the Hunters Point steam units, along with four other fossil fueled plants in the Bay Area, as part of its package proposal for selling off of its fossil-fueled generation. To the extent that there is any "above market" capital investment in these remaining SF generating stations, PG&E may be allowed to recover it through the CTC.

On the negative side for municipalization, AB 1890 states "the obligation to pay the transition costs cannot be avoided by the formation of a local publicly owned electrical corporation"[3] However, this issue may be of limited import because the vast majority of CTC costs, about 78%, will have been recovered by the start of 2002[4], the year we forecast that a municipal could begin operations. The impact of the post 2002 CTC charges for ongoing contractual obligations, even if they could be avoided under the muni scenario, are not significant enough to alter the net benefit or cost of municipalization economics by more than 1% on a net present value basis.[5]

There are other provisions of AB 1890 that give differential treatment to municipal electric utilities as opposed to IOUs. These were discussed in chapter 5. For example, a muni is not mandated to offer direct access to its customers, as are IOUs. This could be viewed as a risk-reduction factor for a municipal electric utility in that its customers could not "by-pass" its power supply portfolio in favor of alternative suppliers.

The FERC, in its Order No.888, issued in early 1996, made a policy statement on stranded costs and the attempt to avoid such costs through municipalization. Quoting from FERC Order No.

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[3] AB 1890 Section 369.

[4] Prepared Testimony of PG&E in Application No. 98-08-070, dated October 21,1996, page EX-2,

[5] This refers to 1% of the total Net Present Value of revenues requirements for a 30-year period begging in 2002.

888 and FERC policy on stranded costs, the FERC Chairman stated the following:

> "The Commission will also treat stranded costs caused by municipalization (or any other case where retail customers become a wholesale customers) as wholesale stranded costs subject to FERC jurisdiction. The Commission expects that it will be the primary forum for cost recovery."[6]

Therefore, avoidance of any portion of the CTC through municipalization seems remote, at most, at this time. In any event, as we stated above, we expect that most (78%) of the CTC will have been collected in rates before an SF municipal electric utility could begin operations. In other words, the economic choice to municipalize in SF is not materially affected by the issues of stranded costs and CTC avoidance.

C. Alternative Municipalization Approaches

The principal alternative to full municipalization has been the so-called "muni-lite" approach whereby the municipality condemns the system only at the meter, leaving the existing utility with ownership and operating responsibility for the remainder of the distribution system. The advantage to the municipal entity is that it could compete with the owner of the distribution system for retail customers without having to purchase the entire distribution system. If the wheeling request is approved by FERC, it may also avoid having to pay "stranded costs" to the existing electric utility. This so-called "muni-lite" approach was attempted by the City of Palm Springs in March 1996 when it filled a Federal Power Act, Section 212 wheeling request to the FERC. The Section 212 request, if approved by FERC, would have required the host utility to transmit Palm Springs-owned electricity to the point of interconnection. That point of interconnection would be the electric meter installed

[6] Statement by D.F. Santa Jr., Commissioner, FERC before the Subcommittee on Energy and Power, Committee on Commerce, U.S. House of Representatives, May 1, 1996.

on the customer side of the host utility's meter. The City of Palm Springs is served by Southern California Edison (SCE). The FERC, in its decision, stated the following regarding the claim that the ownership of meters installed on the customers premises constitutes a municipal electric utility:

> "We cannot agree that owning duplicate meters which simply measure the flow of power from Edison's distribution system to the retail customer meets the statutory requirement,"
>
> "A meter is a measuring and billing device that does not, by itself, accomplish the physical delivery of power. In this case, the distribution facilities that will be delivering the power to Palm Springs customers will continue to be owned by Edison. The installation of meters would not alter this fact [7].

Therefore, unless there is a change in policy at FERC, the so-called "muni-lite" alternative to full municipalization is not an option that merits further consideration.

[7] FERC Decision Docket TX-96-7-000 City of Palm Springs, July 31, 1996.

Glossary of Acronyms

AG&O -- Administrative, general and overhead (costs of utility operation).

AB 1890 -- California Assembly Bill 1890 (1996, Brulte), the legislation restructuring the state's electric industry.

APPA -- The American Public Power Association, an advocacy and service group for U.S. public power authorities.

BAU -- "Business as usual", one of two scenarios used in this study (the other being municipalization). In BAU, PG&E would continue to own the SF electric-distribution system and provide utility service.

CABIS -- Customer accounting, billing, information and services (costs of utility operation)

CCSF -- The City and County of San Francisco, or just "The City" used to refer to the corporate governmental entity, as distinct from the city as a place, which is abbreviated as "SF".

CEC -- California Energy Commission, state agency that regulates resource-planning and related operations of IOU, muni and other public-power utilities in the state.

CPUC -- California Public Utilities Commission, previously the California Railroad Commission or CRC, the agency which regulates retail rates of PG&E and the state's other IOUs.

CTC -- Competition transition charge, provided for in both AB 1890 and the CPUC's earlier electric-industry restructuring. This is a charge applied to each kWh delivered that pays for IOUs' stranded costs due to restructuring.

CVP -- California Central Valley Project (state water-management and power-supply agency).

DSM -- Demand-side management, an approach to satisfying customer needs without power supply or with reduced supplies.

EEI -- Edison Electric Institute, an advocacy and service group for U.S. IOUs.

FERC -- Federal Energy Regulatory Commission, the federal agency which regulates interstate and wholesale transactions between utilities.

GAAP -- Generally accepted accounting principles, the professional rules and standards adopted and adhered to by accountants.

Glossary of Acronyms (Page Two)

GCV -- Going-concern value, the value added to the stand-alone value of a set of assets by a business organization and management. Also sometimes called "goodwill value".

GRC -- General rate case, usually at the CPUC, is a periodic review proceeding by regulators in which a utility's base rates and tariffs are reviewed and approved.

HHWP -- Hetch Hetchy Water & Power (also HHW&P), CCSF/SFPUC unit that supplies water and power to The City and other parties.

IOU -- Investor-owned utilities (here, mainly electric companies), as contrasted to munis and other public-power agencies.

IRR -- Internal rate of return, the rate of return that a project or venture earns.

ISO -- Independent system operator of transmission system in electric-industry restructuring

kWh -- Kilowatt-hour, a basic unit of electric energy, equal to 1 kW of power for 1 hour.

LADWP -- City of Los Angeles Department of Water and Power, the muni water and power utility serving that city.

MID -- Modesto Irrigation District, a water and power district that buys HHW&P power.

MW -- Megawatt, a basic unit of power, equal to 1000 kW. MWH = 1,000 kWh.

NBV -- Net book value, generally the same as original cost, less depreciation, or OCLD.

NPV -- Net present value: equivalent amount today to a future (or past) value, considering difference in time at which the value is actually realized (v. today) and the discount rate used to move values in time. Also NPW (net present worth), or just PV or PW.

O&M -- Operations and maintenance (costs of utility operation).

OCLD -- Original cost, less depreciation, generally the same as net book value, or NBV; also called "historic cost, less depreciation", or HCLD.

PG&E -- Pacific Gas & Electric Company, the gas and electric IOU that has served SF and Northern California for 91 years.

PS -- Physical severance, the damage done (repair costs incurred as a result of) severing one part of a utility system from another. Used in condemnation valuations.

Glossary of Acronyms (Page Three)

PUD --	Public utility district, also known as a public power district for electric service, is a public agency which runs utility operations. Municipals, or munis, are an example.
PX --	Power exchange: market system for buying and selling power under restructuring.
QF --	Qualifying Facility under the federal Public Utility Regulatory Policies Act of 1978, small, cogeneration or "alternative"-fuel mostly non-utility-owned power plant.
RCLD --	Reproduction cost (new) less depreciation (also RCNLD), or replacement cost, net of percent condition, which are formally distinct, but practically equivalent here. Used with SL and SF (e.g., RCL-SF) to designate the depreciation method.
RFQ --	Request for Qualifications -- Professional Services, SFPUC's request for bids for this project, to which ETAG responded, and which determined the scope of work.
ROR --	Rate of return, either on common equity (then, the rate of accounting profit) or on rate base (thus the weighted-average cost of capital).
SCE --	Southern California Edison Company, the electric IOU serving most of Southern California, except Los Angeles and San Diego.
SDG&E --	San Diego Gas & Electric Company, the gas and electric IOU serving that city.
SF --	San Francisco -- the place and its people, as distinct from CCSF. Also refers to sinking-fund (or "economic") depreciation method.
SFOC --	San Francisco Operating Criterion, PG&E's reliability and safety protocols for operating its transmission and generating facilities to serve SF.
SFPUC --	San Francisco Public Utilities Commission, CCSF department which includes HHW&P and other municipal-utility operations.
SL --	Straight-line depreciation method.
SMUD --	Sacramento Municipal Utility District, the electric utility serving that city.
TID --	Turlock Irrigation District, a water and power district that buys HHW&P power.
WAPA --	Western Area Power Authority, federal power marketing and coordination agency.
WPPSS --	Washington Public Power Supply System, public-power group that undertook five ill-fated large power projects in the 1970/80s, leading to then-record U.S. defaults.

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